

Identifying Opportunities for Methane Recovery at U.S. Coal Mines:

Draft Profiles of Selected Gassy Underground Coal Mines

September 1997

**ATMOSPHERIC POLLUTION PREVENTION DIVISION
U.S. ENVIRONMENTAL PROTECTION AGENCY**

COVER PHOTOGRAPHS (clockwise from top): 1) Gas enrichment using pressure swing adsorption, Nelms No. 1 Mine, Ohio. Technology developed by Northwest Fuel Development, Inc. and U.S. DOE. Photo Courtesy of Northwest Fuel Development, Inc. 2) Coal mine methane vehicle refueling station, Zasyadko Mine, Ukraine. Photo courtesy of Raven Ridge Resources, Incorporated. 3) Coal mine methane-fueled generators, Appin Colliery, Australia. Photo courtesy of Energy Developments Ltd. 4) Coal mine methane-fueled brine water evaporator, Morcinek Mine, Poland. Photo courtesy of Aquatech Services, Inc.

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Mine Profiles (profiles appear in alphabetical order by state)

Alabama Mines

Blue Creek No. 3
Blue Creek No. 4
Blue Creek No. 5
Blue Creek No. 7
Mary Lee No. 1
North River No. 1
Oak Grove
Shoal Creek

Colorado Mines

Bowie No. 1
Deserado
Golden Eagle
Sanborn Creek
Southfield
West Elk

Illinois Mines

Brushy Creek
Crown II
Elkhart
Galatia No. 56
Monterey No. 1
Monterey No. 2
Old Ben No. 24
Old Ben No. 25
Old Ben No. 26
Orient No. 6
Pattiki
Rend Lake
Wabash

Indiana Mines

Buck Creek

Kentucky Mines

Arch No. 37
Baker
Camp No. 11
Clean Energy No. 1
Dotiki
Freedom Energy No. 1
Pontiki No. 1
Pontiki No. 2
Wheatcroft No. 9
Wolf Creek No. 4

New Mexico Mines

Cimarron

Ohio Mines

Meigs No. 2
Meigs No. 31
Nelms Cadiz Portal
Powhatan No. 4
Powhatan No. 6

Pennsylvania Mines

Bailey
Cambria No. 33
Cumberland
Dilworth
Emerald No. 1
Enlow Fork
Grove No. 1
Maple Creek
Mine 84
Tanoma
Urling No. 1
Warwick

Utah Mines

Aberdeen
Pinnacle
Soldier Canyon

Virginia Mines

Buchanan No. 1
Bullitt
McClure No. 1
McClure No. 2
VP No. 3
VP No. 8

West Virginia Mines

Arkwright No. 1
Baylor No. 1
Blacksville No. 2
Eagle's Nest
Federal No. 2
Humphrey No. 7
Loveridge No. 22
Maple Meadow No. 1
McElroy
Pinnacle No. 50
Robinson Run No. 95
Sentinel
Shoemaker
Windsor

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Frequently Used Terms

coalbed methane: Methane that resides within coal seams.

coal mine methane: As coal mining proceeds, methane contained in the coal and surrounding strata may be released. This methane is referred to as coal mine methane since its liberation resulted from mining activity. In some instances, methane that continues to be released from the coal bearing strata once a mine is closed and sealed may also be referred to as coal mine methane because the liberated methane is associated with a coal mine.

degasification system: A system that degasifies a mine. Technically, the term degasification refers to removal of methane by ventilation and/or by drainage. However, the term is most commonly used to refer to removal of methane by drainage technology.

drainage system: A system that drains methane from coal seams and/or surrounding rock strata. These systems include vertical pre-mine wells, gob wells and in-mine boreholes.

ventilation system: A system that is used to control the concentration of methane within mine working areas. Ventilation systems consist of powerful fans that move large volumes of air through the mine workings to dilute methane concentrations.

methane drained: The amount of methane drained via a drainage system.

methane liberated: This is the total amount of methane that is released, or liberated, from the coal and surrounding rock strata during the mining process. This total is determined by summing the volume of methane emitted from the ventilation system and the volume of methane that is drained.

methane recovered: The amount of methane that is captured for use rather than emitted to the atmosphere; synonymous with **methane used**.

methane used: The amount of methane that is used as fuel.

methane emissions: This is the total amount of methane that is not used and therefore emitted to the atmosphere. Methane emissions are calculated by subtracting the amount of methane used from the amount of methane liberated.

Frequently Used Abbreviations

b	Billion (10^9)
Btu	British Thermal Unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
cf	Cubic Feet
CH ₄	Methane
CO ₂	Carbon Dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FOB	Freight on Board
GWP	Global Warming Potential
m (or M)	Thousand (10^3)
mm (or MM)	Million (10^6)
MSHA	Mine Safety and Health Administration
MW	Megawatt
NA	Not Available (as opposed to Not Applicable)
PUC	Public Utility Commission
t	ton (short tons are used throughout this report)
USBM	U.S. Bureau of Mines
UMWA	United Mine Workers of America

1. Executive Summary



1. Executive Summary

While miners have traditionally viewed methane as a safety hazard, there is an increasing awareness of the potential environmental, energy and economic benefits achievable by recovering and using this gas, rather than emitting it to the atmosphere. Coal mine methane capture is of interest to gas companies, independent power producers, and possibly to other groups (such as local industries or institutions) that could directly use the methane gas recovered from nearby mines. Electric utilities are also evaluating coal mine methane recovery and use because it represents a cost-effective approach to offsetting their greenhouse gas emissions. Finally, because of potential economic benefits, local governments may find that encouraging the development of coal mine methane recovery and use projects will lead to the creation of new jobs and an increased tax base.

The purpose of this report is to provide information about specific opportunities to develop methane recovery projects at large underground coal mines in the United States. This report contains profiles of 64 U.S. coal mines that may be potential candidates for methane recovery and use. Additionally, the report profiles 15 mines at which successful recovery and use projects have already been developed.¹ The United States Environmental Protection Agency (EPA) designed the profiles to help project developers perform an initial screening of potential projects. While the mines profiled in this report appear to be good candidates, a detailed evaluation would need to be done on a site-specific basis in order to determine whether the development of a specific methane recovery project is both technically and economically feasible.

Since the last version of this report was published in September 1994, coalbed and coal mine methane recovery and use has continued to develop and grow. As a testament to this, the number of mines with recovery and use projects has increased from 10 in 1994 to at least 17 in 1997. As a result, gas recovery and sales have also increased, from an estimated 35 bcf in 1994 to nearly 49 bcf in 1996. At a gas price of \$2/mcf, this means that coal mine methane developers increased annual revenues by an estimated \$28 million between 1994 and 1996.

Benefits of Methane Recovery

Methane is the principal component of natural gas, and methane that is recovered from coal mines in high concentrations can be used for energy purposes. Today, there are methane recovery and use projects at mines in Alabama, Colorado, Ohio, Pennsylvania, Virginia, and West Virginia. EPA estimates that methane recovery at these mines was nearly 49 billion cubic feet in 1996. As shown in this report, there are many additional gassy coal mines, at which projects have not yet been developed, that offer the potential for the profitable recovery of methane.

In addition to the direct financial benefits that may be enjoyed from the sale of coal mine methane, indirect financial and economic benefits may also be achieved. Degasification systems that are used to drain methane prevent gas from escaping into mine working areas, increase methane recovery, improve worker safety, and significantly reduce ventilation costs at

¹ The report also discusses, but does not profile, two additional mines at which methane recovery and use projects are underway. These mines are not profiled because they have not emitted significant quantities of methane to the atmosphere since they have been closed and sealed.

several mines. Increased recovery also reduces methane-related mining delays, resulting in increased coal productivity. Furthermore, the development of methane recovery projects has been shown to result in the creation of new jobs, which has helped to stimulate area economies.² Additionally, the development of local coal mine methane resources may result in the availability of a potentially low-cost supply of gas that could be used to help attract new industry to a region. For these reasons, encouraging the development of coal mine methane recovery projects is likely to be of growing interest to state and local governments that have candidate mines in their jurisdictions.

As a greenhouse gas, methane is approximately 21 times more potent than carbon dioxide (CO₂) in terms of the impact on global warming over a 100 year time frame. Since methane is such a potent greenhouse gas, reducing methane emissions results in large environmental benefits. For example, some of the mines profiled in this report have methane emissions in excess of five million cubic feet per day (or nearly two billion cubic feet per year). Developing a project at one of these mines that would recover half of this methane, or nearly one billion cubic feet per year, would result in emissions reductions that would be the equivalent of 0.44 million tons of CO₂ emissions.³ Because of the large environmental benefits that may be achieved, coal mine methane projects may serve as cost-effective alternatives for utilities and others seeking to offset their own greenhouse gas emissions.

Overview of Recovery and Use Techniques

Methane gas (CH₄) and coal are formed together during coalification, a process in which biomass is converted by biological and geological processes into coal. Methane is stored within coal seams and also within the rock strata surrounding the seams. Methane is released when pressure within a coalbed is reduced as a result of natural erosion, faulting, or mining. Deep coal seams tend to have a higher average methane content than shallow coal seams, because the capacity to store methane increases as pressure increases with depth. Accordingly, underground mines release substantially more methane than surface mines, per ton of coal extracted.

Coal mine methane emissions may be mitigated by the implementation of methane recovery projects at underground mines. Mines can use several reliable degasification methods to drain methane. These methods have been developed primarily to supplement mine ventilation systems that were designed to ensure that methane concentrations in underground mines remain within safe concentrations. While these degasification systems are mostly used for safety reasons, they can also recover methane that may be employed as an energy resource. Degasification systems include vertical wells (drilled from the surface into the coal seam months or years in advance of mining), gob wells (drilled from the surface into the coal seam just prior to mining), and in-mine boreholes (drilled from inside the mine into the coal seam or the surrounding strata prior to mining).

² For example, see discussion on this subject in the report "The Environmental and Economic Benefits of Coalbed Methane Development in the Appalachian Region" (USEPA, 1994).

³ The carbon dioxide equivalent of methane emissions is calculated by determining the weight of methane collected (on a 100% basis), using a density of 19.2 g/cf. The weight is then multiplied by the global warming potential (GWP) of methane, which is 21 times greater than carbon dioxide over a 100 year time period.

The quality (purity) of the gas that is recovered is partially dependent on the degasification method employed, and determines how the gas can be used. For example, only high quality gas (typically greater than 95% methane) can be used for pipeline injection. Vertical wells and horizontal boreholes tend to recover nearly pure methane (over 95% methane). In very gassy mines, gob wells can also recover high-quality methane, especially during the first few months of production. Over time, however, mine air may become mixed with the methane produced by gob wells, resulting in a lower quality gas.

Even lower quality methane can be used as an energy source in various applications. Potential applications that have been demonstrated in the U.S. and other countries include:

- electricity generation (the electricity can be used either on-site or can be sold to utilities);
- as a fuel for on-site preparation plants or mine vehicles, or for nearby industrial or institutional facilities; and,
- cutting-edge applications, such as in fuel cells.

It is also possible to enrich lower quality gas to pipeline standards using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development. Another option for improving the quality of mine gas is blending, which is the mixing of lower quality gas with higher quality gas whose heating value exceeds pipeline requirements.

Even mine ventilation air, which typically contains less than 1% methane, is being successfully used as combustion air in gas-fired internal combustion engines in Australia. The technology for using mine ventilation air as combustion air in turbines and coal-fired boilers also exists. Research on the use of thermal oxidizers and catalytic reactors to generate heat from methane in mine ventilation air is also underway.

Opportunities for Methane Recovery Projects

While methane recovery projects already are operating at some of the gassiest mines in the U.S., there are numerous additional gassy mines at which recovery projects could be developed. As mentioned previously, this report profiles 15 mines that already sell recovered methane. The report also profiles 64 mines that are potential candidates for the development of coal mine methane projects. Of these candidate mines, 49 are currently operating. Another 15 mines have been idled, will be closing, or have closed.

The closed, closing, and idled mines are included here because many still may present opportunities for methane recovery. In the U.S. there are several examples of successful methane recovery projects at abandoned mines, such as in Ohio where an active mine (Nelms Cadiz Portal) uses electricity generated from methane that is recovered from a nearby abandoned and sealed mine (Nelms No. 1).

At least 21 of the profiled mines that are currently operating use drainage systems as a supplement to their ventilation systems; of these mines, 14 sell recovered methane⁴. Drainage

⁴ These figures do not include the Golden Eagle Mine, which closed in 1995 and no longer uses a ventilation system, but does recover methane for sale.

efficiency, which is the percentage of all liberated methane that a mine drains, typically ranges from 25 to 60 percent.⁵ Mines that already use drainage systems may be especially good candidates for the development of cost-effective methane recovery projects, since the drainage equipment is already in place.

Overview of Methane Liberation, Drainage and Use at Profiled Mines

This report profiles mines located in 11 states. West Virginia has the largest number of profiled mines (14), followed by Illinois (13) and Pennsylvania (12). In 1996, the 79 mines profiled in this report liberated an estimated 382 mmcf/d of methane, or about 140 bcf/yr. Table 1-1 shows the number of profiled mines and the estimated total methane liberated from these mines. Table 1-1 summarizes information presented in the state summaries and individual mine profiles (Chapter 6). Chapter 4 explains how these data were derived.

Table 1-1: U.S. Summary Table

Number of Profiled Mines and Estimated Methane Liberated and Used in 1996¹

State	Operating but not Using Methane		Closed/Closing/Idle		Operating and Using Methane		All Mines Profiled in This Report		
	Number Of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Estimated Methane Use (mmcf/d)
Alabama	1	3.0	1	1.5	6	115.8	8	120.3	59.0
Colorado	5	10.9	1 ²	0.0	0	0.0	6	10.9	0 ²
Illinois	9	20.5	4	3.2	0	0.0	13	23.7	0
Indiana	0	0.0	1	0.3	0	0.0	1	0.3	0
Kentucky	8	7.7	2	0.5	0	0.0	10	8.2	0
New Mexico	0	0.0	1	0.0	0	0.0	1	0.0	0
Ohio	5	4.4	0	0.0	0	0.0	5	4.4	0 ³
Pennsylvania	10	54.0	2	1.1	0	0.0	12	55.1	0
Utah	2	4.8	1	0.2	0	0.0	3	5.0	0
Virginia	1	1.0	2	1.9	3	72.0 ⁴	6	74.9 ⁴	73.0
West Virginia	8	18.8	2 ⁵	7.7	4	53.0	14	79.5	1.9
TOTAL:⁶	49	125.1	17	16.4	13	240.8	79	382.3	133.9
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (49 mines):							Methane (bcf/yr)	CO₂ (mmt/yr)	
1996 Estimated Total Emissions							45.7	20.3	
Estimated Annual Avoided Emissions if Recovery Projects are Implemented							18.3-27.4	8.1 - 12.2	

⁵ Please see Chapter 4 for a more detailed discussion of this issue.

¹ Chapter 4 explains how these data were estimated.

² A methane recovery project began at a closed Colorado mine in 1997.

³ Does not include 0.18 mmcf/d of methane recovered from a closed mine that is being used to generate electricity.

⁴ This value may be underestimated. See Virginia sections (pages 3-8 and 6-10) for further discussion.

⁵ Includes an idle/closing mine that is using methane.

⁶ Values shown here do not always sum to totals due to rounding.

Table 1-1 shows that of the 79 profiled mines, there are 13 operating mines using methane, 2 idle/closed mines using methane, 49 operating mines that are not using methane, and 15 closed, closing, or idle mines that are not using methane. Currently, about 35% of the estimated methane liberated from profiled mines is being used.

The bottom of Table 1-1 shows estimated annual methane emissions from the mines that are operating but not using methane, and their CO₂ equivalents. The table also shows estimated annual emissions of methane and CO₂ equivalents that would be avoided by implementing methane recovery and use projects at these mines, assuming a 40-60% range of recovery efficiency. Based on this recovery efficiency, if methane recovery projects were implemented at profiled mines that are currently operating but do not recover methane, an estimated 18-27 bcf/yr of methane emissions would be avoided. This is equivalent to about 8-12 mmt/yr of CO₂. Moreover, there is significant potential for increased methane recovery at many of the mines that already have recovery projects.

Summary of Opportunities for Project Development

The number of methane recovery projects in the United States has increased in recent years as coal, gas, and electricity producers have become familiar with the technology for methane recovery and use. Most underground coal mines do not recover and use methane, however, the profiles indicate that many of these mines appear to be strong candidates for cost-effective recovery projects. Furthermore, this report contains information suggesting that substantial environmental, economic, and energy benefits could be achieved if mines that currently emit methane were to recover and use it.

The mines profiled in this report are quite variable in terms of the amount of methane they liberate, their gassiness or "specific emissions" (methane liberated per ton of coal mined), and their annual coal production. The volume of methane liberated from each mine ranges from less than 0.3 mmcf/d to over 30 mmcf/d. Similarly, specific emissions range from less than 50 cf/ton to over 5,000 cf/ton. Annual coal production ranges from less than 500,000 tons at some mines to over 5 million tons per year at others. All these factors are important indicators of the potential profitability of developing a project at an individual mine. Furthermore, as shown in the profiles (Chapter 6), the candidate mines vary with respect to other important factors that affect profitability, such as the distance from the mine to a pipeline or the projected remaining productive life of the mine. Accordingly, the overall feasibility of developing a methane recovery project will likely vary widely among the candidate mines.

Although a number of the mines profiled here show strong potential for profitable projects, methane ventures at these mines are not currently being developed, due to a number of barriers to coal mine methane development. Many of these barriers are being overcome, and

the time to develop methane recovery and use projects has never been better. Gas prices have improved, increasing the economic benefits of coalbed methane recovery. Restructuring of the gas industry has created new market opportunities for coal mine methane, and the potential for distributed generation is increasing as a result of electricity industry restructuring. At the same time, utilities are seeking opportunities to offset greenhouse gas emissions and to develop "environmentally friendly" projects.

Chapter 2 provides an introduction to coal mine methane in the U.S., including a discussion of major developments in the burgeoning coal mine methane recovery industry that have transpired since publication of the previous version of this report in 1994. Chapter 3 discusses current coal mine methane recovery projects in the U.S., and Chapter 4 provides a key to evaluating the mine profiles. This information, together with the summary tables presented in Chapter 5, and the state summaries and actual mine profiles in Chapter 6, should assist potential investors in assessing the overall potential project profitability. If projects are initiated at even a few of the mines profiled here, substantial methane emissions reductions and increased profits for developers could be achieved, thereby benefiting the U.S. economy and the global environment.

2. Introduction

2. Introduction

Purpose of Report

This report provides information about specific opportunities to develop methane recovery and use projects at large underground mines in the United States. Groups that may be interested in identifying such opportunities include utilities, natural gas resource developers, independent power producers, and local industries or institutions that could directly use the methane recovered from a nearby mine.

This introduction provides a broad overview of the technical, economic, regulatory, and environmental issues concerning methane recovery from coal mines. The report also presents an overview of existing methane recovery and use projects (Chapter 3). Information that will assist the reader in understanding and evaluating the data presented in Chapters 5 and 6 of this report is found in Chapter 4. Chapter 5 contains data summary tables, and finally, Chapter 6 profiles individual underground coal mines that appear to be good candidates for the development of methane recovery projects.

Recent Developments in the Coal Mine Methane Industry

Since the last version of this document was published in September 1994, there have been significant developments in coal mine methane recovery, particularly in the number of active recovery and use projects. The number of mines with active methane recovery and use projects has grown from 10 in 1994 to at least 17 in 1997¹. Similarly, the amount of methane recovered has grown from an estimated 35 bcf in 1994 to nearly 49 bcf in 1996. At a gas price of \$2/mcf, this means that coal mine methane developers increased revenues by an estimated \$28 million from 1994 to 1996. The resulting decrease in methane emissions has yielded benefits to the global environment as well through reducing greenhouse gas emissions equal to more than 25 mmt/year of CO₂. Figure 2-1 shows the growth in the number of mines engaging in coal mine methane recovery since 1994 and Figure 2-2 shows the growth in the amount of gas being recovered.

The growth in the number of coal mines recovering methane can be attributed to four primary factors: 1) more coal mine operators are now familiar with the technology used to recover methane; 2) coal mine methane developers are beginning to use methane for a variety of purposes besides pipeline injection; 3) legislation concerning ownership issues has been enacted in most coalbed methane producing states; and 4) various projects have proven the profit-generating potential of coal mine methane recovery. Also, as discussed later in this chapter, the issuance of FERC Orders 636 and 888 is removing barriers to free and open competition in the natural gas and electric utility industries, respectively. As a result of these orders, coal mine methane developers should encounter fewer problems accessing available capacity of the nation's gas and electric transmission lines.

¹ This report profiles 15 mines with methane recovery and use projects. Chapter 3 also discusses two additional projects underway at mines that are closed. Because these mines have been sealed and have not emitted significant quantities of methane to the atmosphere, they are not profiled in this report.

Figure 2-1: Mines with Active Coal Mine Methane Recovery Projects

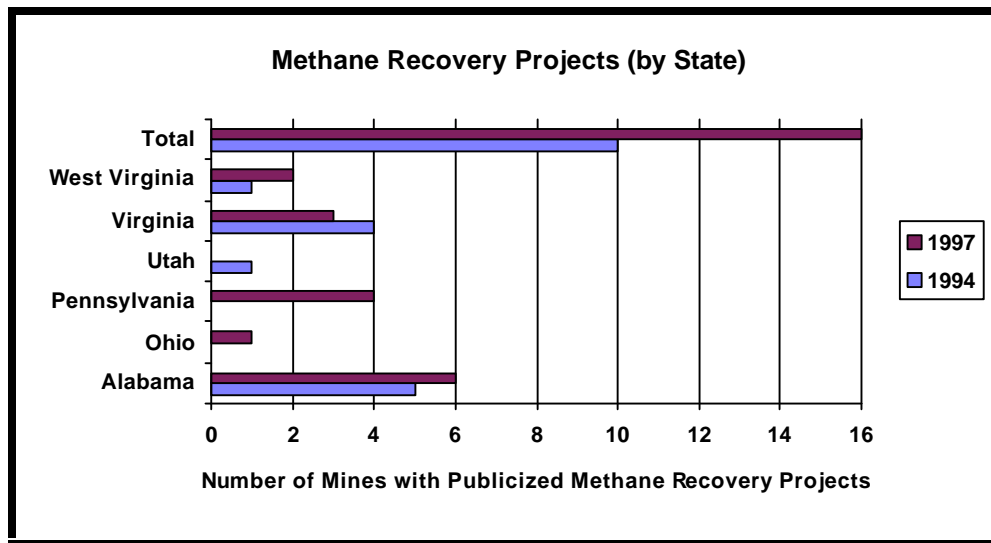
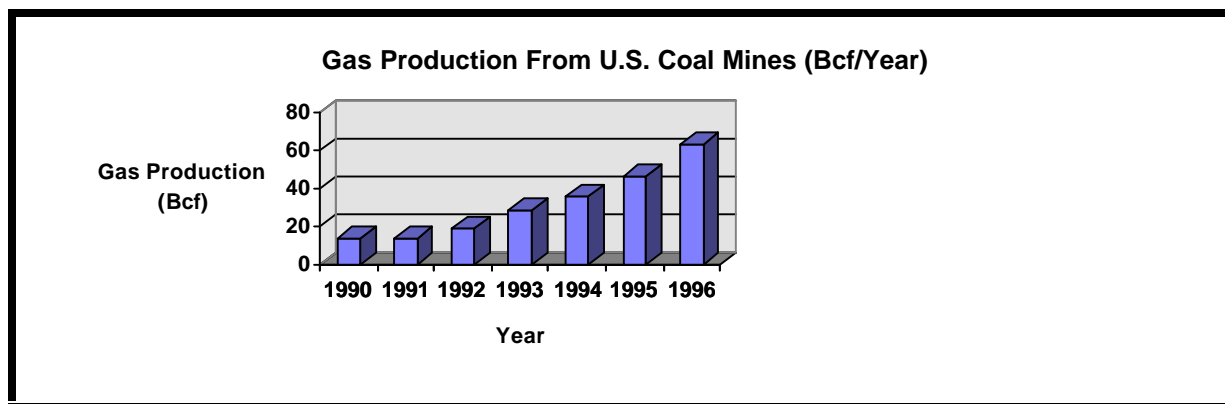


Figure 2-2: Estimated Annual Use of Methane Recovered From U.S. Coal Mines (based on publicly available information)



Overview of Coal Mine Methane

Methane and coal are formed together during coalification, a process in which vegetation is converted by geological and biological forces into coal. Methane is stored in large quantities within coal seams and also within the rock strata surrounding the seams. Two of the most important factors determining the amount of methane that will be stored in a coal seam and the surrounding strata are the rank and the depth of the coal. Coal is ranked by its carbon content; coals of a higher rank have a higher carbon content and generally a higher methane content.² The capacity to store methane increases as pressure increases with depth. Thus, within a given coal rank, deep coal seams tend to have a higher methane content than shallow ones.

² In descending order, the ranks of coal are: graphite, anthracite, bituminous, sub-bituminous, and lignite. Most U.S. production is bituminous or sub-bituminous.

Methane concentrations typically increase with depth, therefore underground mines tend to release significantly higher quantities of methane per ton of coal mined than do surface mines. In fact, while only 40 percent of U.S. coal is produced in underground mines, these mines account for over 70 percent of estimated methane emissions from coal mining (USEPA, 1993a). The low methane content of surface mined coals virtually eliminates the potential for profitable recovery and use of methane released during mining. Therefore, options for recovering and using methane are available for underground mines only. Among underground mines, the largest and gassiest mines typically have the best potential for profitable recovery and utilization of methane.

Methane (CH₄) is one of the principal greenhouse gases,³ second only to carbon dioxide (CO₂) in its contribution to global warming. Methane is responsible for roughly 18 percent of the total contribution of all greenhouse gases based on "radiative forcing," the measure used to determine the extent to which the atmosphere is trapping heat due to emissions of greenhouse gases. On a gram for gram basis, methane is a more potent greenhouse gas than carbon dioxide (about 21 times greater over a 100 year time frame). Because of methane's potency and short atmospheric lifetime, reductions in methane emissions will produce even greater environmental benefits in the short-run.

Methane emissions resulting from coal mining activities account for about 10 percent of annual global methane emissions from anthropogenic (man-made) sources. The People's Republic of China is the largest emitter of coal mine methane, followed by the countries of the former Soviet Union (primarily Russia and Ukraine) and then the United States (USEPA, 1993c). In 1995, coal mining emissions were estimated to account for 12 percent of total U.S. methane emissions (USEPA, 1997).

Methane Drainage Techniques

In underground mines, methane poses a serious safety hazard for miners because it is explosive in low concentrations (5 to 15 percent in air). By law, methane concentrations may not exceed one percent in mine working areas and two percent in all other locations. In some underground mines, methane emissions can be controlled solely through the use of a ventilation system, which pumps large quantities of air through the mine in order to dilute the methane to safe levels. In particularly gassy mines, however, the ventilation system must be supplemented with a drainage system. Drainage systems reduce the quantity of methane in the working areas by draining the gas from the coal-bearing strata before, during, or after mining, depending on mining needs. Emissions from drainage systems are estimated to account for one-fourth to nearly one-half of the total methane emissions from underground coal mining. At least 25 of the mines profiled in this report have some type of drainage system. Of these mines, 21 are operating and draining methane, 1 is closed and draining methane, and the remaining 3 are closed and not currently draining methane.

Over the years, the economic benefits of employing drainage systems have also been realized by mine operators. For mines that have drainage systems in place, the cost of ventilation is significantly reduced because the drainage systems recover a significant percentage of the associated methane. Use of methane drainage systems also helps reduce production costs,

³ Greenhouse gases are those gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and re-emit infrared radiation.

as there are typically fewer methane-related delays at mines that employ drainage systems (Kim and Mutmanský, 1990). Today, methane drainage is a proven technology and much of the gas that is recovered can be used in various applications.

While drainage systems are currently used primarily for economic and safety reasons to ensure that methane concentrations remain below acceptable levels, these systems recover methane that also can be employed as an energy source. The quantity and quality of the methane recovered will vary according to the method used. The quality of the recovered methane is measured by its heating value. Pure methane has a heating value of about 900 British Thermal Units per cubic foot (Btu/cf), while a mixture of 50 percent methane and 50 percent air has a heating value of approximately 500 Btu/cf.

Drainage methods include vertical wells (vertical pre-mine), gob wells (vertical gob), longhole horizontal borehole, and horizontal and cross-measure boreholes. The preferred recovery method will depend, in part, on mining methods and on how the methane will be used. In some cases, an integrated approach using a combination of the above drainage methods will lead to the highest recovery of methane. The key features of the methane recovery methods are discussed in more detail below.

Vertical Pre-Mining Wells

Vertical pre-mining wells are the optimal method for recovering high quality gas from the coal seam and the surrounding strata before mining operations begin. Pre-mine drainage ensures that the recovered methane will not be contaminated with ventilation air from mine working areas. Similar in design to conventional oil and gas wells, vertical wells can be drilled into the coal seam several years in advance of mining. Vertical wells, which may require hydraulic or nitrogen fracturing of the coal seam to activate the flow of methane, typically produce gas of over 90 percent purity. However, these wells may produce large quantities of water and small volumes of methane during the first several months they are in operation. As this water is removed and the pressure in the coal seam is lowered, methane production increases.

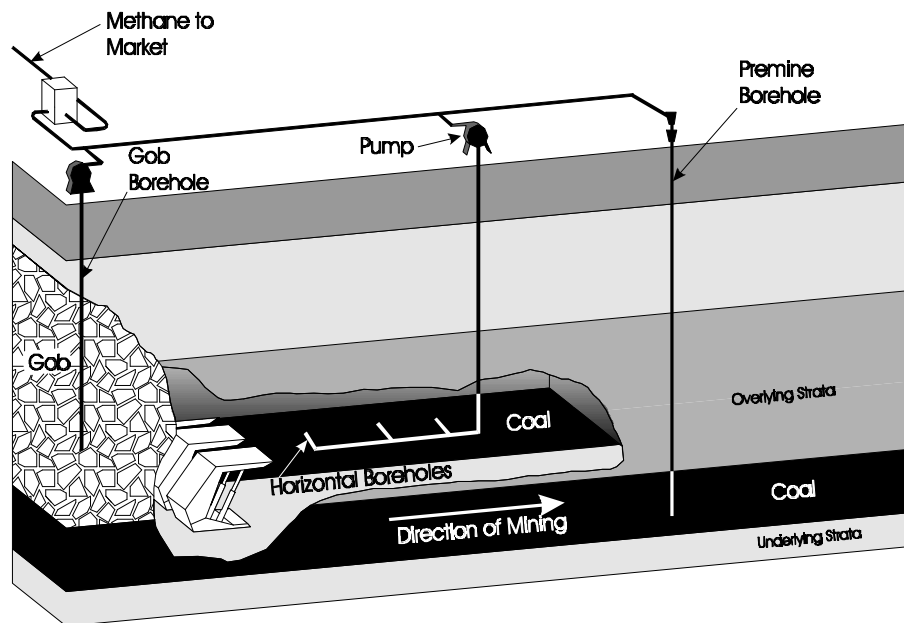
The total amount of methane recovered using vertical pre-drainage will depend on site-specific conditions and on the number of years the wells are drilled prior to the start of mining. Recovery of from 50 to over 70 percent of the methane that would otherwise be emitted during mining operations is likely for operations in which vertical degasification wells are drilled more than 10 years in advance of mining.⁴ Although not previously used widely in the coal mining industry, vertical wells are increasing in popularity within the coal industry, and are used by numerous stand-alone operations⁵ that produce methane from coal seams for sale to natural gas pipelines. In some very low permeability coal seams, vertical wells may not be a cost-effective technology due to limited methane flow. Furthermore, there is some concern that in certain geologic conditions the hydraulic fracturing may cause damage to the roof rock, which would hinder mining operations. Vertical wells, however, will likely continue to be a viable recovery technology for most underground mines.

⁴ The range of potential recovery is based on estimates in USEPA 1990 and USEPA 1991.

⁵ The term "stand-alone" refers to coalbed methane operations that recover methane for its own economic value. In most cases, these operations recover methane from deep and gassy coal seams that are not likely to be mined in the near future.

About 11 underground mines in the U.S. currently use vertical pre-mining wells. A majority of these mines already recover methane for pipeline sales (see section on existing methane recovery projects). Figure 2-3 illustrates a vertical pre-mine well.

Figure 2-3: Vertical Pre-Mining Gob, and Horizontal Boreholes



Gob Wells

Gob wells are drilled from the surface to a point 10 to 50 feet above the target seam prior to mining. As mining advances under the well, the methane-charged strata that surround the well fracture. Relaxation and collapse of strata surrounding the coal seam creates a fractured zone known as the "gob" area, which is a significant source of methane. Methane emitted from the gob flows into the gob well and up to the surface. A vacuum is frequently used on the gob wells to prevent methane from entering mine working areas.

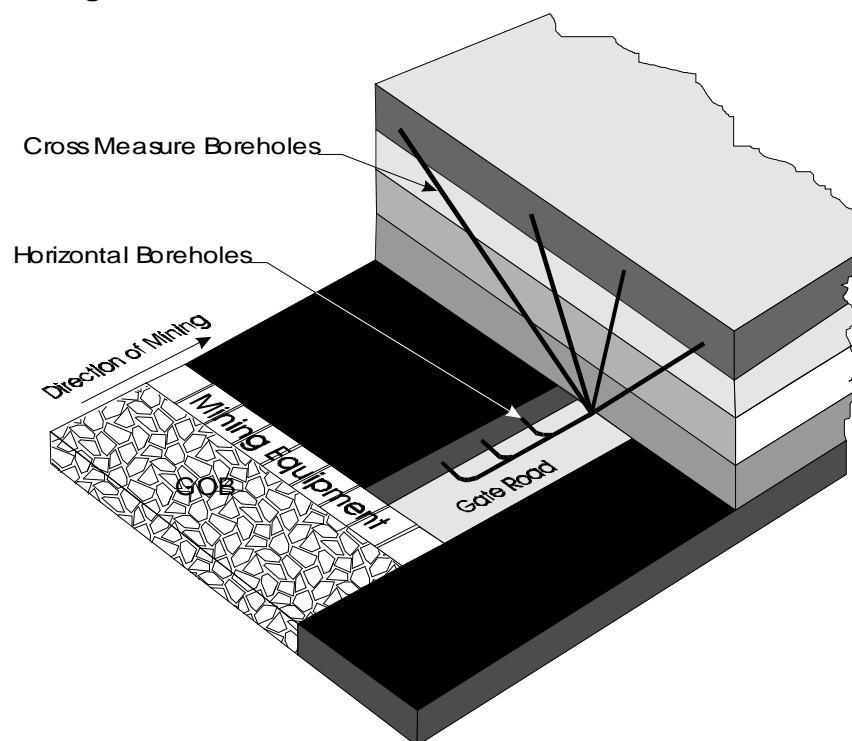
Initially, gob wells produce nearly pure methane. Over time, however, additional amounts of mine air can flow into the gob area and dilute the methane. The heating value of "gob gas" normally ranges between 300 and 800 Btu/cf. In some cases, it is possible to maintain nearly pure methane production from gob wells through careful monitoring and management. Jim Walter Resources, CONSOL, and Peabody are all using techniques for producing high-quality gas from gob wells. Gas production rates from gob wells can be very high, especially immediately following the fracturing of the strata as mining advances under the well. Jim Walter Resources reports that gob wells initially produce at rates in excess of two million cubic feet per day. Over time, production rates typically decline until a relatively stable rate is achieved, typically in the range of 100 mcf/d. Depending on the number and spacing of the wells, gob wells can recover an estimated 30 percent to over 50 percent of methane emissions associated with coal mining (USEPA, 1990).

About 22 U.S. mines currently use surface gob wells to reduce methane levels in mine working areas. Most mines release methane drained from gob wells into the atmosphere. Figure 2-3 illustrates a vertical gob well.

Horizontal Boreholes

Horizontal boreholes are drilled inside the mine (as opposed to from the surface) and they drain methane from the unmined areas of the coal seam, or from blocked out longwall panels shortly before mining takes place. These boreholes are typically 400 to 800 feet in length. Several hundred boreholes may be drilled within a single mine and connected to an in-mine vacuum piping system, which transports the methane out of the mine and to the surface. Most often, horizontal boreholes are used for short-term methane emissions relief during mining. Because methane drainage only occurs from the mined coal seam (and not from the surrounding strata), the recovery efficiency of this technique is low -- approximately 10 to 18 percent of methane that would otherwise be emitted (USEPA, 1990). However, this methane typically can have a heating value of over 950 Btu/cf (USEPA, 1991). About 16 underground mines in the U.S. currently use this technique to reduce the quantity of methane in mine working areas. Figures 2-3 and 2-4 illustrate horizontal boreholes.

Figure 2-4: Horizontal and Cross-Measure Boreholes



Longhole Horizontal Boreholes

Like horizontal boreholes, longhole horizontal boreholes are drilled from inside the mine in advance of mining. They are greater than 1000 feet in length and are drilled in unmined seams using directional drilling techniques. Longhole horizontal boreholes produce nearly pure methane with a recovery efficiency of about 50% and therefore can be used when high quality gas is desired. This technique is most effective for gassy, low permeability coal seams that require long diffusion periods. The Soldier Canyon Mine in Utah used long-hole horizontal boreholes to recover methane for sale to pipeline companies, as noted in Chapter 6.

Cross-Measure Boreholes

Cross-measure boreholes degasify the overlying and underlying rock strata surrounding the target coal seam. These boreholes are drilled inside the mine and they drain methane with a heating value similar to that of gob wells. Cross-measure boreholes have been used extensively in Europe and Asia but are not widely used in the United States where surface gob wells are preferred. Figure 2-4 illustrates cross-measure boreholes.

Table 2-1 summarizes the key features of the drainage methods discussed above.

Table 2-1				
Summary of Drainage Methods				
Method	Description	Gas Quality	Drainage Efficiency ^a	Current Use in U.S. Coal Mines
Vertical Wells	Drilled from surface to coal seam months or years in advance of mining.	Produces nearly pure methane.	up to 70%	Used by at least 3 U.S. mining companies in about 11 mines.
Gob Wells	Drilled from surface to a few feet above coal seam just prior to mining.	Produces methane that is sometimes contaminated with mine air.	up to 50%	Used by approximately 22 mines.
Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 20%	Used by approximately 16 mines.
Longhole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 50%	Used by over 10 mines.
Cross-measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata shortly prior to mining.	Produces methane that is sometimes contaminated with mine air.	Up to 20%	Not widely used in the U.S.
Source: USEPA (1993b).				
^a Percent of total methane liberated that is drained.				

Utilization Methods

Once recovered, coal mine methane is an energy source available for many different applications. Potential utilization methods are pipeline injection, electricity generation, and direct use in on-site prep-plants or to fuel mine vehicles, or at nearby industrial or institutional facilities. Following is a discussion of various utilization methods. Table 2-2 shows the recovery methods that may be employed for each utilization option.

Table 2-2 Utilization Options for Coalbed Methane		
Utilization Options	Range of Btu Quality (Btu/cf)	Recovery Method
Pipeline Injection Power Generation Local Use (at on-site coal prep plant or to fuel mine vehicles, or at nearby industrial or institutional facilities)	> 950	Vertical Wells (Pre-mining degasification)
Pipeline Injection (requires (1) maintaining pipeline quality or (2) gas enrichment) Power Generation Local Use	300 to 950	Gob Wells
Pipeline Injection Power Generation Local Use	up to 950	In-Mine Boreholes
Use as combustion air in gas-fired IC engines, gas turbines or coal-fired boilers; thermal oxidation; catalytic reactors	10 to 20	Ventilation Air
Sources: USEPA (1990); USEPA (1991)		

Pipeline Injection

Methane liberated during coal mining may be recovered and collected for sale to pipeline companies. The key issues that will determine project feasibility are: 1) whether the recovered gas can meet pipeline quality standards; and 2) whether the costs of production, processing, compression and transportation are competitive with other gas sources.

U.S. experience demonstrates that selling recovered methane to a pipeline can be profitable for mining companies and is by far the most popular use method. As shown in Table 2-3, fifteen of the profiled mines currently sell methane from their drainage systems to local pipeline companies. Chapter 3 contains additional information on these projects.

Technical Feasibility

The primary technical consideration involved in collecting coal mine methane for pipeline sales is that the recovered methane must meet the standards for "pipeline quality" gas. First, it must have a methane concentration of at least 95 percent and contain no more than a 2 percent concentration of gases that do not burn (i.e., carbon dioxide, nitrogen, helium). Additionally, any non-methane hydrocarbons are usually removed from the gas stream for other uses. Hydrogen sulfide (which mixes with water to make sulfuric acid) and hydrogen (which makes pipes brittle) must also be removed before the gas is introduced into the pipeline system. Finally, any water or sand produced with the gas must be removed to prevent damage to the system. While coalbed methane requires water removal, it is often free of hydrogen sulfide

and other impurities typically found in natural gas. With proper recovery and treatment, coalbed methane can meet the requirements for pipeline quality gas.

Table 2-3		
Current Coal Mine Methane Pipeline Projects at Profiled Mines		
Mining Company	Number of Mines	State
Jim Walter Resources	4	Alabama
U.S. Steel Mining	2	Alabama, West Virginia
Drummond Coal	1	Alabama
Basin Resources	1	Colorado
Consolidation Coal Company	3	West Virginia/Pennsylvania*
Eastern Associated Coal (Peabody)	1	West Virginia
CONSOL Coal Group	3	Virginia
* While the main entries for these three mines (which are part of a single methane recovery project) are located in West Virginia, significant portions of the mines extend into Pennsylvania, and most of the gas production is from Pennsylvania.		

Vertical degas wells are the preferred recovery method for producing pipeline quality methane from coal seams because pre-mining drainage ensures that the recovered methane is not contaminated with ventilation air from the working areas of the mine. Gob wells, in contrast, generally do not produce pipeline quality gas as the methane is frequently mixed with ventilation air. In certain cases, however, it is possible to maintain a higher and more consistent gas quality through careful monitoring and adjustment of the vacuum pressure in gob wells. For example, Jim Walter Resources, Inc. (JWR) successfully uses gob wells to recover methane for pipeline injection at its Alabama mines.⁶

⁶ See, for example, Dixon (1989).

It is also possible to enrich gob gas to pipeline quality using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development and may prove to be economically attractive and technically feasible with additional research⁷. For example, CONSOL's Buchanan No. 1 Mine was the site of a demonstration project for enriching medium quality gob gas to pipeline standards (Shirley et al, 1997). In the first phase of the project, BOC Gases and CONSOL installed a small pressure swing adsorption (PSA) pilot plant at the mine for characterizing the technique in terms of performance, safe start-up, and shutdown. In the second phase of the demonstration, a commercial scale PSA unit was installed to produce high-purity methane from approximately 0.1-0.2 mmcf/d of gob gas. The pilot unit was able to produce high-quality methane from gob gas containing about 70 percent methane, with minimal methane loss.

EnviroGas Recovery, Inc. and CBE, Inc. are also undertaking a gas enrichment project at several West Virginia/Pennsylvania mines (see discussion under "Pennsylvania" in Chapter 3). A gas enrichment project at the Nelms No. 1 Mine in Ohio is also underway (see discussion under "Ohio" in Chapter 3).

Another option for improving the quality of mine gas is blending, which is the mixing of lower Btu gas with higher Btu gas whose heating value exceeds pipeline requirements. As a result of blending, the Btu content of the overall mixture can meet acceptable levels for pipeline injection. For example, the JWR mines in Alabama are blending higher quality coalbed methane with gob gas prior to pipeline delivery. Similarly, the Noumenon Corporation of Core, West Virginia, is blending gas from West Virginia mines with high-Btu gas or propane and selling the product to several utilities.

Horizontal boreholes and longhole horizontal boreholes also can produce pipeline quality gas when the integrity of the in-mine piping system is closely monitored. However, the amount of methane produced from these methods is sometimes not large enough to warrant investments in the necessary surface facilities. In cases where mines are developing utilization strategies for larger amounts of gas recovered from vertical or gob wells, it may be possible to use the gas recovered from in-mine boreholes to supplement production.

Profitability

The overall profitability of recovering methane for pipeline injection will depend on a number of factors. These factors include the amount and quality of methane recovered (as discussed above), the capital and operating costs for wells, water disposal, compression and gathering systems, and, most importantly, the price at which the recovered gas may be sold.

The costs for disposal of production water from vertical wells may be a significant factor in determining the economic viability of a project, as discussed later in this chapter ("Production Characteristics of Coalbed Methane Wells"). The cost of gas gathering lines is another consideration. Because costs for laying gathering lines are high, proximity to existing commercial pipelines is a significant factor in determining the economic viability of a coalbed methane project. Most coal mines are located within 20 miles of a commercial pipeline (ICF Resources, 1990b; ICF, 1995). However, in some cases, existing pipelines may have limited capacity for transporting additional gas supplies. Costs for laying gathering lines vary widely depending, in part, on terrain. The hilly and mountainous terrain in many mining areas increases the difficulty, and thus the cost, of installing gathering lines.

⁷ The U.S. EPA is preparing a report on the technical options for gas upgrading.

Another determinant of the overall profitability of a pipeline injection project is a mine's ability to find a purchaser for its recovered gas. A methane recovery project will also need to demonstrate that its recovered methane is of the requisite pipeline quality.

The passage of Federal Energy Regulatory Commission (FERC) Order 636 in 1992 switched the natural gas industry from a regulated to a market-based system, thereby making it easier for coalbed methane producers to access the natural gas market. The fundamental change from the post-Order 636 period is that gas prices are now determined by supply and demand forces, whereas during the pre-Order 636 period prices were determined based on rates set by federal regulators (see "New Investment Opportunities" section later in this chapter).

Power Generation

Coalbed methane may also be used as a fuel for power generation. Unlike pipeline injection, power generation does not require pipeline quality methane. Gas turbines can generate electricity using methane that has a heat content of 350 Btu/cf. Mines can use electricity generated from recovered methane to meet their own on-site electricity requirements and can sell electricity generated in excess of on-site needs to utilities. The Nelms No. 1 Mine in Ohio currently uses recovered methane to generate power, which is subsequently transmitted to the neighboring Nelms Cadiz Portal Mine where it is used on-site. Additionally, several power generation projects are operating at coal mines in China, Australia, England, and Germany (Sturgill, 1991).

Like the natural gas industry before it, the electric utility industry is in the midst of restructuring. One result of FERC Order 888 is that coal mine operators now have as much access to the country's transmission lines as any other energy developer (see "New Investment Opportunities" section later in this chapter). Depending on the outcome of utility restructuring there could be enhanced opportunities for coalbed methane producers as generating utilities seek the cheapest raw material from which to generate power. To the extent that coalbed methane prices remain competitive with coal and other raw materials, the potential for using coalbed methane to generate electricity is promising.

Technical Feasibility

A methane/air mixture with a heating value of at least 350 Btu/cf is a suitable gaseous fuel for electricity generation. Accordingly, vertical degas wells, gob wells, and in-mine boreholes are all acceptable methods of recovering methane for generating power. Gas turbines, internal combustion (IC) engines, and boiler/steam turbines can all be adapted to generate electricity from coalbed methane. Fuel cells may also prove to be a promising option and are currently being tested at the Nelms No. 1 Mine in Ohio (see Chapter 3). Currently, the most likely generator choice for a coalbed methane project would be either a gas turbine or an IC engine. Boiler/steam turbines are generally not cost effective in small sizes (e.g., below 30 MW). Gas turbines are smaller and lighter than IC engines and historically have had lower operation and maintenance costs.

While maintaining pipeline quality gas output from gob wells can be difficult, the heating value of gob gas is generally compatible with the combustion needs of gas turbines. In fact, gases with even lower heating values (100 to 250 Btu/cf) have been used successfully in some generators. One potential problem with using gob gas is that production, methane concentration, and rate of flow are generally not predictable; wide variations in the Btu content

of the fuel may create operating difficulties. Equipment for blending the air and methane may be needed to ensure that variations in the heating value of the fuel remain within an acceptable range -- approximately ten percent allowable variability for gas turbines.

A potential advantage of using vertical pre-mine wells as the recovery method for power generation is that the quantity and quality of methane produced is more consistent than that of gob wells. Thus, problems stemming from variations in the heating value of the fuel would be minimized where vertical wells are employed. Another option is to blend high quality gas from vertical wells with lower quality gas from gob wells to ensure consistent quality. Horizontal boreholes also can produce gas of consistently high quality. The limited quantity of gas produced by this method would likely need to be supplemented by larger quantities of methane from vertical or gob wells, however.

The level of electric capacity that may be generated depends on the amount of methane recovered and the "heat rate" (i.e., Btu to kWh conversion) of the generator. For example, simple cycle gas turbines typically have heat rates in the range of 10,000 Btu/kWh, while combined cycle gas turbines could have heat rates of 8,000 Btu/kWh. Assuming a conservative heat rate of 11,000 Btu/kWh and assuming that mines could recover 35 percent of total emissions, the level of electric capacity that could be sustained by the top twenty methane-emitting mines would likely exceed 10 MW per mine.

Use of Mine Ventilation Air to Generate Power or Heat

At some mines, methane emissions from ventilation air could be avoided by using the ventilation air as combustion air in IC engines, boilers, or turbines. Currently, the Appin Colliery in Australia is using mine ventilation air as combustion air in 54 methane-fueled IC engines rated at 1 MW each. Appin recovers an estimated 1.3 mmcf/d of methane from ventilation air for this purpose (Mining Engineering, 1997), increasing overall plant output by an estimated 7 to 10% (Greenhouse Challenge, 1996). Utilization of methane emitted in ventilation air could potentially be economic for on-site power generation in the U.S. where the ventilation air would only need to be transported a short distance. Distances greater than five miles are likely not to be cost effective. The technology for using ventilation air as combustion air in boilers or turbines exists, but has not yet been demonstrated at a coal mine in the U.S. and is not discussed further here.

There are at least two well-established technologies under investigation for using methane from mine ventilation air. One type consists of thermal oxidizers, which oxidize gases containing low concentrations of volatile organic compounds, such as methane. At methane concentrations of 0.2 volume percent, thermal oxidizers can produce net energy (Mattus, 1997). This technology is therefore capable of oxidizing mine ventilation air to produce heat. The heat that is generated via this process could then be used in a number of applications, including power generation.

Another type of technology, the catalytic reactor, is capable of combusting methane at lower temperatures than those required by thermal oxidizers, through the use of a catalyst. The Canadian Government research organization, CANMET, is in the process of developing a catalytic reactor at the Phalen Coal Mine in Cape Breton, Nova Scotia. The unit, scheduled for completion in 1998, will initially use about 280 ft³/sec of ventilation air to provide heat to mine surface facilities. If successful, the project will be scaled up to use 7,240 ft³/sec of ventilation air (King, 1997).

Profitability: Power Generation for On-Site Use

Given their large energy requirements, coal mines may realize significant economic savings by generating power from recovered methane. Nearly every piece of equipment in an underground mine operates on electricity, including mining machines, conveyor belts, ventilation fans, and elevators. Much of the equipment at typical mines is operated 250 days a year, two shifts per day. Ventilation systems, however, must run 24 hours a day, 365 days a year, and they demand a considerable amount of electricity -- up to 60 percent of the mine's total needs (USBM, 1992).

A mine's total electricity needs can exceed 24 kWh per ton of coal mined. Since the largest underground mines in the U.S. produce more than 2 million tons of coal annually, they may purchase over 48 million kWh of electricity annually. At average industrial electricity rates of five cents per kWh, a mine's electricity bill can exceed several million dollars a year.

Coal preparation plants, which are frequently located near large mines, also consume a great deal of energy. Preparation involves crushing, cleaning, and drying the coal before its final sale. Coal drying operations require thermal energy, which could be generated by a turbine or engine in a cogeneration cycle. Coal preparation generally requires an additional 6 kWh per ton of coal (ICF Resources, 1990a).

Among the main factors in determining the economic viability of generating power for on-site use are the total amount and flow of the methane recovered, the capital costs of the generator, the expected lifetime of the project, and the price the mine pays for the electricity it uses. A mine would need to be fairly large to recover an amount of methane that would justify the capital expenditures for a generator and other equipment needed for utilizing power on-site. Moreover, because the \$/kW capital cost of a generator is relatively high in terms of the overall economics of a coalbed methane power project, the mine would need to generate power for several years in order to justify the capital investment. A final economic consideration is the cost of back-up power, which is typically supplied by a utility and is essential for mining operations given their safety considerations.

Profitability: Off-Site Sale to a Utility

Large and gassy coal mines may be able to generate electric power from recovered methane in excess of their own power requirements. In such cases, a mine may be able to profit from selling power to a nearby utility. Additionally, under some circumstances, a mine might arrange to sell electricity to a utility, but continue to purchase electricity from the utility for its own on-site use. The economic feasibility of selling power off-site would depend on the amount of electricity that could be generated, the incremental costs of selling power to a utility, and the price received for the electricity.

If a mine is generating power to meet its own electricity needs, the incremental costs of selling excess power off-site are relatively low. Normally, a coal mine already has a large transmission line running from a main transmission line to the mine substation. In most cases, this same line could be used to transmit power from the mine back to the utility. For some

mines, an interconnection facility or line upgrades may be needed to feed this additional power into the main line.

Local Use

In addition to pipeline injection and power generation, coal mine methane may be used as a fuel in on-site preparation plants or vehicle refueling stations, or it can be transported to a nearby coal-fired boiler or other industrial or institutional facilities for direct use.

Nearly all large underground coal mines have preparation plants located nearby. Mines have traditionally used their own coal to fuel these plants, but there is the potential to use recovered methane instead. Currently, CONSOL uses recovered methane to fuel the thermal dryer in one of its preparation plants. In Poland, several coal mines have used recovered methane to fuel their coal drying plants.

Another option for on-site methane use may be as a fuel for mine vehicles. Natural gas is much cheaper and cleaner than diesel fuel or gasoline, and internal combustion engines burn it more efficiently. The cost of building fueling stations, which was at one time prohibitive, has decreased markedly (Castille, 1996), and more than 80,000 compressed natural gas vehicles are currently in use in the U.S. (USDOE, 1996a). In Ukraine, a degasification company drains methane from gob areas of the Zasyadko Mine to fuel vehicles.

In addition to on-site methane use, selling recovered methane to a nearby industrial or institutional facility may be a promising option for some mines. An ideal gas customer would be located near the coal mine (within five miles) and would have a continuous demand for gaseous fuel. Coal mine methane could be used to fuel a cogeneration system, to fire boilers or chillers, or to provide space heating. In some cases, local communities may find that the availability of an inexpensive fuel source from their local mine can help them attract industry and generate additional jobs.

In the past, methane recovered from a coal mine in Monongalia County, West Virginia, was reportedly used in a nearby glass factory. Additionally, there are numerous international examples of mine gas being used for industrial purposes. For example, in Ukraine and Russia, recovered methane is used in coal-fired boilers located at the mine-site. In the Czech Republic, coal mine methane is used in nearby metallurgical plants. In Poland, recovered methane is used as a feed-stock fuel in a chemical plant. In China, methane has been used in carbon black plants.

Experiences using recovered landfill gas may also provide relevant examples. Currently, there are a number of U.S. projects where methane recovered from landfills is being used at nearby industrial or institutional facilities. For example, landfill gas recovered from the Prince Georges County landfill in Maryland is transported a few miles to a nearby prison, where the gas is utilized in the prison's boiler system. Another example of a local use project is the Wilder's Grove landfill located in Raleigh, North Carolina. At this landfill, approximately 1.3 million cubic feet of gas per day is recovered and then piped one mile to a pharmaceutical plant for use as boiler fuel. The boiler, rated at 26,800 pounds per hour of steam on natural gas, produces nearly 24,000 pounds of steam per hour for use at the pharmaceutical plant. As extracted, landfill gas has an approximate heating value of 450 to 550 Btu/cubic foot. This medium-Btu

gas often must be processed to meet the requirements of the facility utilizing the gas. Some facilities, however, may be able to use the raw gas without purification. While there are some notable differences between landfill and coal mine methane projects, the technical and economic feasibility of such projects can be fairly similar.⁸

Finally, co-firing methane with coal in a boiler is another potential utilization option, particularly for mines that are located in close proximity to a power plant. A few of the mines profiled in this report are located within a few miles of a coal-fired plant (for example, Robinson Run is located about three miles from Monongahela Power's Harrison Plant).

Flaring

Environmentally, flaring methane is nearly as beneficial as utilizing the methane as fuel, since flaring changes the majority of the methane to carbon dioxide. Emitting carbon dioxide is much less harmful in terms of the impact on global warming than is the direct emission of methane. For purposes of greenhouse gas reductions, the value of recovering one ton of methane and using it to generate energy (in lieu of burning natural gas from a traditional source) is equivalent to a 21 ton reduction in carbon dioxide emissions. If mine emissions are flared without using the combustion to displace energy from other sources, flaring yields greenhouse gas reductions equal to 87.5% of those achievable through recovery and use (Lewin, 1997).

To date, flaring has not been considered in the U.S. as a possible option for mitigating coal mine methane emissions because of safety concerns. The principal concern expressed is that it is not safe to pipe the gas to a point where it would be flared because of the potential for the flame to propagate back down to the mine and to cause an underground explosion (Lewin, 1995). Even if flame arresters were used and the gas were piped to a flare located away from the mine, an additional concern is that it may not be safe to compress gob gas because certain air/methane mixtures may become explosive when compressed.

If agreement on the safe practice of flaring methane recovered from coal mines is reached, flaring could become an additional option for mitigating methane emissions. The flaring option requires addressing the concerns of miners, mine owners, MSHA, and union parties. If these concerns can be addressed, mine operators could use flaring as a means of reducing greenhouse gas emissions.

Barriers to the Recovery and Use of Coal Mine Methane

While a number of U.S. coal mines are already selling recovered methane to pipelines, numerous seemingly profitable projects have not been undertaken at other mines. Currently, a number of problems and disincentives exist that distort the economics of coal mine methane projects, with the result that many potentially profitable investments are not being developed. These obstacles include unresolved legal issues concerning ownership of the coalbed methane resource, constraints to project development, and other remaining technical challenges.

⁸ Landfill gas is typically a mixture of 50 percent carbon dioxide and 50 percent methane; consequently, the heating value of the gas is normally about 500 Btu/cf. In comparison, depending on the recovery method employed, the heating value of gas recovered from coal mines may range from 300 to over 900 Btu/cf.

Ownership of Coalbed Methane

Unresolved legal issues concerning the ownership of coalbed methane resources have constituted one of the most significant barriers to coalbed methane recovery. Ambiguity in certain state legal systems provides a disincentive for investment in coalbed methane projects because of the uncertainties as to which parties may demand compensation for development of the resource. Coalbed methane industry forums have identified ownership issues as serious obstacles to methane recovery, particularly in Pennsylvania (USEPA, 1997). As interest in coalbed methane recovery increases, and profitable exploitation of this resource becomes generally recognized, disputes over ownership may be expected to increase.

Coalbed methane ownership is a complicated issue by virtue of the nature of the resource itself. Conventional gas and oil resources are found in different, usually deeper, strata than the strata containing minable coal reserves. Thus, rights to mineral reserves of the same tract of land may be easily separated, according to strata, between the owner of the coal rights and the owner of the gas and oil rights. However, clear geological separation may not exist for coalbed methane. Coalbed methane is a gas resource located in the same strata as coal reserves, making separation of ownership problematic. In addition, coalbed methane traditionally was not considered a potentially profitable resource worthy of attention during the leasing process. Thus, it is usually not clear under older leases whether the owner of the coal development rights is also the owner of the associated coalbed methane resources. Potentially, ownership could rest with the holder of the coal rights, the owner of oil and gas rights, the surface owner, or some combination of the three. The situation may be further complicated by the fact that there may be more than one owner of the gas and oil rights, the coal rights, and the surface rights. The multiplicity of owners tends to be particularly severe in the Appalachian region.

The U.S. Congress passed coalbed methane ownership legislation as part of the Energy Policy Act of 1992. Under this act, several states were either categorized as "affected" states, or were "exempted", i.e., not subject to the requirements of the act. The act provided for affected states either to develop regulations to resolve the issue of coalbed methane ownership, or to opt out of the act, or to comply with federal forced pooling arrangements as dictated by the act. Generally, affected states were those that had the potential for coalbed methane development, but whose regulatory structure did not address coalbed methane ownership disputes, thereby leading to a decline in development of coalbed methane. The states that were categorized as "affected" are Tennessee, West Virginia, Pennsylvania, Kentucky, Ohio, Indiana, and Illinois. The states that were exempted are Colorado, New Mexico, Montana, Wyoming, Utah, Virginia, Washington, Mississippi, Louisiana, and Alabama.

As described below, the state of West Virginia passed its own forced pooling regulations in April 1994 in response to the requirements of the Energy Policy Act. Of the remaining six affected states, Pennsylvania, Ohio, Indiana, and Illinois opted out of the federal program. Tennessee and Kentucky did not pass their own regulations, nor did they opt out. Therefore, in disputes requiring intervention, both Tennessee and Kentucky apply forced pooling regulations as stipulated under the Energy Policy Act.

In 1994 the West Virginia legislature enacted a bill designed to provide comprehensive regulation of coalbed methane recovery. While making clear that coalbed methane recovery should not interfere with the mining of coal, the legislature sought to encourage coalbed methane development. A key provision of the statute establishes a coalbed methane review board. Among other things, the board is charged with the responsibility of issuing permits for

coalbed methane wells and, where mineral rights are in conflict, of establishing appropriate pooling arrangements for dividing the proceeds from the recovery of coalbed methane. The legislation requires the posting of a bond prior to the issuance of a permit for a coalbed methane well. In addition, coal operators who vent methane solely for the purpose of mining coal are exempt from the legislation's provisions.

Of the exempted states, Virginia and Alabama have unilaterally passed their own regulations to deal with this issue. The remaining exempted states handle coalbed methane issues through normal legal channels (Department of the Interior, 1997).

Virginia has been among the most pro-active states in attempting to address the question of coalbed methane ownership. Virginia originally tried to legislate ownership with passage of the Migratory Gas Act of 1977. This legislation determined that, in leases entered into after 1977, ownership of coalbed methane rested with the surface property owner, unless otherwise provided for by law. However, industry concerns and questions of constitutionality led to the repeal of this act in 1990. Instead of attempting to legislate ownership, Virginia adopted an approach that allows for coalbed methane projects to proceed in instances when ownership is still undecided. As the culmination of a series of revisions to its Gas and Coal Act, in 1990 Virginia adopted an amendment allowing for development of coalbed methane in cases in which ownership remains uncertain or in dispute. In such situations, the Virginia Gas and Oil Board may enact "forced pooling" of all potential interests in the coalbed methane. Until such time as ownership is decided, costs or proceeds attributable to the conflicting interests are paid into an escrow account. The amount that is escrowed is currently under review. In the past, the law had required that any monies under dispute be escrowed until a resolution was reached. However, operators have varying interpretations of this regulation and it is expected that in the future the Virginia Oil and Gas Board will determine the percentage of monies to be escrowed on a case-by-case basis (Virginia Gas and Oil Board, 1997b).

States that currently have not resolved coalbed methane ownership issues potentially hinder the development of a coalbed methane industry in their states. Developers often consider the risks too high because of the potential liability that they have to bear. Developers can be sued for trespassing, can lose much of their investment in the project, and can have their cash flow and projects stopped while disputes work their way through the courts. Ultimately, as a criterion to investing in a coalbed methane project, investors depend on an unambiguous definition of a state's coalbed methane ownership.

Constraints to Project Development

Conditions in the coal mining industry may adversely affect the industry's consideration of potentially profitable methane recovery projects for a number of reasons, including:

- *Capital Constraints.* Methane recovery and utilization projects require relatively large capital investment. Given competition and the need to justify large capital expenditures, attracting this level of investment may be difficult.

Some states, however, provide financial incentives to encourage methane recovery. In April 1995, the state of Virginia passed a coalbed methane state tax credit as part of an initiative to increase coal industry employment. The amount of the credit is one cent per million Btu of coalbed methane produced in the state. The state of Alabama has a severance package available that allows coalbed methane developers to pay less tax than conventional natural gas producers. State agencies may also be rich sources of

information concerning grants, finance sources and other incentives that may be available to a coal mine methane developer.⁹

There are a number of creative financing ventures occurring to help spur coalbed methane recovery. A variety of financial instruments can be used to finance projects; the two most common types are equity and debt. In equity financing, investors are owners of the project. In debt financing, lenders to the project are not usually shareholders in the project. Debt investors are solely concerned with recovering their investment plus interest. Debt investors are paid before distributions can be made to shareholders. There are also a number of less popular vehicles that can be used to finance coalbed methane projects, including debt/equity hybrids, leases, insurance policies and performance bonds.¹⁰ However, despite the above financial vehicles, many coalbed methane projects have been financed through corporate resources rather than project-specific debt and equity.

- *Emphasis on Productivity.* Since the early 1980s, most coal companies have placed highest priority on investments in increased coal productivity. This preference, combined with a shortage of investment capital, could make it more difficult for companies to consider systems for methane recovery and utilization. For mines where high gas emissions pose a safety hazard, however, these projects can enhance productivity. EPA and the Pennsylvania State University are researching the connection between degas and productivity, with the goal of quantifying how much degasification systems can contribute to mine productivity.
- *Future Uncertainty.* Given a constantly evolving industry and global competition, many coal companies are uncertain about their future level of operation. Coal companies concerned about their long-term viability may be hesitant to invest in long-term methane recovery projects.
- *Perception of Risk.* As with any new technology, decision-makers unfamiliar with methane recovery and utilization may be hesitant to commit to such projects because of the possibility of unforeseen problems, and because they are unconvinced that methane recovery can be profitable. This fear can be minimized by engaging the services of a third party developer who is knowledgeable about coal mine methane recovery.

Production Characteristics of Coalbed Methane Wells

Gas Production

Coalbed methane degasification wells have production characteristics that differ from conventional gas wells in a variety of respects. One important difference is the amount of control the developer has in terms of the gas flow. With conventional gas wells, the gas flow may be controlled, or completely halted, at the discretion of the operator. This provides the operator with flexibility as to when the gas is sold. Vertical pre-mine degasification wells can be controlled as their production is not directly related to mining activities. In-seam and gob wells,

⁹ For more information on state and federal opportunities, please refer to EPA 430-R-95-013, *Finance Opportunities for Coal Mine Methane Projects: A Guide for West Virginia*, EPA 430-R-95-014, *Finance Opportunities for Coal Mine Methane Projects: A Guide to Federal Assistance*, and EPA 430-R-95-008, *Finance Opportunities for Coal Mine Methane Projects: A Guide for Southwestern Pennsylvania*.

¹⁰ For more information on financial vehicles, please see EPA publication EPA-430-B-97-001, *A Guide to Financing Coalbed Methane Projects*.

however, are not subject to the same control by virtue of their purpose. These wells are used primarily to drain a mine of methane for safety reasons. As such, the feasibility of turning off and on an in-seam or gob well depends on safety first and gas production second.

This production characteristics of coalbed methane wells present difficulties in the context of the natural gas and pipeline industries. Much of the consumer demand for natural gas is seasonal in nature. In addition, in situations of limited pipeline capacity, local pipelines may not be able to accept the gas supplied from coalbed methane projects on a continuous, uninterrupted basis. In particular, some areas of the Appalachian region have limited pipeline capacity. As a result, a shrewd gas marketer who understands the unique needs of coal mine methane producers will want to structure all gas sales contracts to take into account that the supplier has a continuous supply of gas. Storage of coalbed methane in depleted natural gas reservoirs or abandoned mines is an excellent means of overcoming problems related to fluctuations in demand or pipeline capacity. EPA is currently investigating the potential for storing methane recovered from active coal mines in nearby abandoned coal mines.

Water Production

Another area in which technical challenges may arise is water disposal. In many instances, vertical coalbed methane wells will produce water from the coal seam and surrounding strata. Water is also produced during conventional mining operations, but some states have adopted separate regulations for water produced in association with coalbed methane operations and for water produced as a result of mining operations. For mines located near fresh water bodies or other vulnerable areas, surface water disposal may not be environmentally acceptable. Several alternative disposal and treatment methods are in use or under development, including deep well injection and other surface treatment approaches. These treatments may have higher costs associated with them, and in some cases additional research is necessary to address technical issues.

This issue tends to vary from state to state, and it is necessary for developers to contact appropriate agencies. For example, coalbed methane operators in Alabama addressed environmental concerns related to water disposal by forming the Warrior Basin Environmental Cooperative (WBEC). WBEC comprises all of the major sources of coalbed methane-related water production in the Warrior Basin. In 1990, WBEC began operating continuous water quality monitors along a 150-mile segment of the Black Warrior River. This system operator notifies responsible parties immediately by phone or fax if there is an increase in chloride levels in any part of the 150-mile segment.

The program has been highly successful in demonstrating to the Alabama Department of Environmental Management (ADEM) and other concerned parties that chloride levels in the Black Warrior River have remained well under EPA and ADEM limits. The continuous monitoring program costs an average of \$10-\$17 thousand per month to operate, however, so ADEM has been granted a reduction in monitoring requirements that will reduce these costs. Under the new requirements, monitoring will be less expensive, but the ability to detect and prevent a water quality violation will not be compromised.

New Investment Opportunities

Because of its energy value, coal mine methane can provide economic benefits for gas developers, electric utilities and other energy producers, as well as state and local governments. For example, a report by EPA (USEPA, 1994) evaluated the potential economic

benefits that could be achieved through the development of coalbed methane projects in the Appalachian region. The analysis indicated that coalbed methane production in the Appalachian region could directly create up to 1,000 jobs by year 2000 and 2,500 jobs by year 2010. The analysis further indicated that, in addition to employment benefits, coalbed methane production could generate state revenues of more than \$6 million in 2000, and \$20 to \$25 million in 2010. Such estimates are comparable to the revenues realized by other states that have encouraged the development of coalbed methane resources.

Restructuring of the U.S. energy industry, together with electric utilities' impetus to reduce greenhouse gas emissions and develop sources of green power, are creating new opportunities for coal mine methane projects. Following is an overview of three primary forces that have important implications for the coal mine methane market.

Implications of FERC Order 636 for the Coal Mine Methane Market

Passage of FERC Order 636 in 1992 has changed the natural gas industry from a regulated industry to one that is market-based. The fundamental change in the post-Order 636 period is that gas prices are now determined by forces of supply and demand, whereas during the pre-Order 636 period, gas prices were determined based on rates set by federal regulators. These changes can affect coal mine methane producers in the following ways:

- Producers now have numerous potential markets and opportunities to sell gas. Most gassy coal mines are located near major gas consuming markets, and with the ability to sell gas through marketers or directly to local distribution companies or end-users, producers can now easily access these markets.
- Coal mine methane producers now have a greater opportunity to tailor gas sales contracts to meet their needs and production characteristics.
- Transportation access is no longer a barrier to reaching the secondary markets; however, the cost of making the physical connections to local markets and other related pipeline capacity additions will be a factor in individual situations.
- With the seasonal demand for gas, and the high costs of pipeline capacity, gas storage is at a premium. As noted previously, the use of abandoned coal mines for storage may be an additional option for mine operators that would both increase the marketability of coal mine methane and provide a valuable service to the gas market.

The price at which the recovered gas may be sold is a critical factor in determining whether a project will be economically viable. It is currently estimated that 21 coal mines could recover methane for a profit in 2000 if the wellhead gas price was \$2.00 per thousand cubic feet (mcf). Additional scenarios are shown in Table 2-4.

As shown in Table 2-4, gas price has a large impact on the amount of methane recovered and on the number of mines that are able to recover it profitably. Currently, the average U.S. wellhead gas price is about \$2.00/mcf, though several sources project that wellhead gas prices will likely increase over the next decade. The price that coal mine methane producers receive for their gas depends on gas quality and reliability of production, the location of the gas relative to competing supplies, and the extent to which a mine operator can create value through the addition of related services, such as storage. While Order 636 has created strong

opportunities for coal mine methane producers, it is important that producers employ creativity in contracting and pricing to ensure competitiveness with conventional natural gas.

Table 2-4 Estimated Profitable Emissions Reductions In 2000		
Wellhead Gas Price (\$/mcf)	Methane Recovered * (Bcf/yr)	Number of Mines Recovering
\$1.75	76.1	18
\$2.25	82.9	22
\$3.00	88.1	28
Based on emissions analysis conducted by ICF Incorporated for the U.S. EPA, April, 1997. * These numbers assume that 60 percent of total methane liberated from these mines could be recovered for sale.		

Implications of FERC Order 888 for the Coal Mine Methane Market

Like the natural gas industry before it, the electric utility industry is in the midst of restructuring. The issuance of FERC Order 888 in 1996 initiated open access to electric lines. As a result, most states are still grappling with issues surrounding conversion to a competitive environment, while some have made great progress toward creating a competitive electric marketplace. Ultimately, opportunities for coalbed methane developers will depend on the final outcome of state-by-state initiatives related to electric utility restructuring. Table 2-5 provides an overview of the status of electric utility restructuring in the states that have candidate mines.

Analysts are uncertain as to the exact course electric utility restructuring will follow, but it is generally agreed that competition is coming, and as a result of competitive pressures, energy efficiency will improve. Electric industry restructuring has several implications for the development of coalbed methane.

Current predictions indicate that coal and natural gas will fuel a majority of the country's new capacity in the coming years, and about 20 percent of that capacity will be supplied by distributed (decentralized) power projects. On-site power plants at mines are an example of distributed power. Moreover, locating generators nearer to consumers reduces the need to install new transmission capacity. As such, local utilities could use distributed power to help retain large customers (such as coal mines) who would otherwise self-generate or buy power from the lowest bidder. Utilities may find that the best way of retaining coal mines as clients is to provide them with the equipment and financing they need to self-generate. The utility would earn profits by financing and selling equipment, providing operating and maintenance services, selling backup power, and selling that power which was formerly sold to the mine, to other markets.

Table 2-5: Status of Electric Utility Restructuring Efforts in Selected States

State	Status of Electric Utility Restructuring Effort
Alabama	Governor signed bill granting state utilities full stranded cost recovery, through exit fees, for up to five years after wheeling is introduced in Alabama.
Colorado	Seven electric industry restructuring bills were introduced in January, 1997, but all failed.
Illinois	A pending bill would reduce rates by 15 percent for all consumers and would guarantee full stranded cost recovery for utilities. The plan would be phased-in, over a four-year period, beginning in October 1999. The bill has passed the Illinois House, but not the Senate.
Indiana	Introduced a plan that would bring electricity provider choice to the state by October 1, 1999. The bill has been challenged and is currently being amended. Introduction of the new bill is expected in 1998.
Kentucky	The Public Service Commission is sponsoring legislation that will permit alternative rate-making. End-user groups are opposing the legislation. No other formal discussions are taking place.
New Mexico	Discussions are taking place. The issue of stranded investments is controversial.
Ohio	A joint legislative committee has been formed to study retail competition and restructuring issues. The committee must issue a recommendation by October 1, 1997.
Pennsylvania	In 1996, Pennsylvania became the fourth state to legislate retail electricity competition. Retail competition will be phased in over three years beginning January 1, 1999, by adding one-third of the state's load each year.
Utah	A task force has been formed to study electric utility restructuring. A bill, with recommendations for implementation, is due November 1997.
Virginia	State regulators lack interest in retail competition. The proposed approach is to proceed cautiously.
West Virginia	A formal investigation has started into retail competition. The Public Service Commission counseled against deregulation due to ample low-cost generation, and the fact that 70% of generation is sold out-of-state.
Sources: Strategic Energy Limited monthly briefings on happenings in electricity restructuring; Edison Institute's Regulatory Briefing Service; National Regulatory Research Institute (www.nrri.Ohio-State.edu)	

No one knows for certain which course electric restructuring may take, and some analysts argue that under competitive pressure, utilities may lower their reserve margins, thereby causing an increase in generation at existing large-scale facilities rather than the construction of new, smaller capacity plants. If this occurs, it could limit electric utility investment in coal mine methane projects.

Utility Offset and Green Pricing Projects

Green Pricing

With the advent of competition in the electric utility industry, utilities are recognizing the need to provide new services to the customers. One such service is "green pricing". Under green pricing, customers have a choice regarding the type of electricity they choose to purchase. Customers could choose conventional power, which they could purchase at a standard rate, or they could purchase green power at a slightly higher rate. As part of the green pricing program, for every customer who commits to pay the higher rate, the utility pledges to buy enough "environmentally friendly" energy to completely offset the customer's share of conventionally generated electricity. Niagara Mohawk, for example, was one of the country's first utilities to implement a green pricing program. The utility filed for regulatory approval of a green pricing plan that includes a \$6/month customer surcharge. One dollar of this would go for tree planting, and the remaining five dollars would go toward development of renewable resources.

Ultimately, a properly implemented green pricing program can provide positive marketing for a utility, since the utility is working to improve the environment, and customers are assured of this action because they are participants. Additionally, utilities may find that investing in green power is lucrative when the value of greenhouse gas reductions and avoided expansion of conventional generating facilities is taken into account. Given these benefits, the potential for green power seems promising.

Utility Offsets

Coalbed methane recovery projects can also provide a means of offsetting utility emissions. Utilities could choose to participate in a green pricing program as described above, or in several additional ways as listed in Table 2-6.

Table 2-6: Options for Utilities to Achieve Greenhouse Gas Reductions

<p>Utilities could achieve coal mine methane greenhouse gas reductions in any of a number of ways:</p> <ul style="list-style-type: none"> • Investing directly in a coal mine methane recovery project; • Purchasing emission reductions from coal mines that recover methane; • Arranging "green coal" deals where the utility includes greenhouse gas emission reduction reports with coal purchases; • Swapping SO₂ allowances for greenhouse gas emission reductions; and • Participating in a multi-utility coal mine methane recovery project and sharing the emission reductions.

Utilities have chosen various routes to achieve greenhouse gas reductions. Ohio Power buys electricity generated using recovered coal mine methane from the Nelms No. 1 Mine. This "green" power displaces other conventionally generated power, thereby leading to reduced carbon dioxide emissions (Voluntary Reporting of Greenhouse Gases, 1995; EIA, 1996). Niagara Mohawk has traded carbon dioxide reductions in exchange for sulfur dioxide allowances. Various coal companies structure deals to include greenhouse gas credits so that the price of coal is more appealing to utility purchasers.

With competition in the electric industry underway in many parts of the country, utilities are seeking least-cost offsets for planned conventional generating expansions. Coalbed methane projects have proved to be good least-cost offsets. One such example is a planned offset

project at the Nelms No. 1 Mine in Cadiz, Ohio. Projects are currently underway to expand the power project at Nelms No. 1, and to have that expansion count as a greenhouse gas offset project. The developer of the new electric thermal plant will use the greenhouse gas reductions to offset projected emissions associated with the new plant.

3. Overview of Existing Coal Mine Methane Projects

3. Overview of Existing Coal Mine Methane Projects

Coal mine methane recovery and use is a proven technology. This chapter discusses methane recovery and use projects at 15 mines profiled in Chapter 6. This chapter also discusses current methane recovery projects at two additional mines, the Nelms No. 1 Mine in Ohio and the Blacksville No.1 Mine in West Virginia¹. These mines are not profiled in Chapter 6 because they do not emit large volumes of methane to the atmosphere, but they are excellent examples of profitable projects at closed mines.

In 1996, total methane sales from coal mine methane projects at profiled mines was nearly 49 billion cubic feet, which is the equivalent of nearly 22 million tons of carbon dioxide.² At the current wellhead gas price of roughly \$2 per thousand cubic feet, and assuming that all recovered gas was sold to a pipeline, these projects collectively will have grossed approximately \$98 million dollars in annual revenues. Additionally, by working to maximize the amount of gas recovered from their drainage systems, these projects have greatly reduced mine ventilation costs and have improved safety conditions for miners. The projects in Alabama, Colorado, Ohio, Pennsylvania, Virginia, and West Virginia employ a variety of degasification techniques, including vertical wells (pre-mining degasification), gob wells, and in-mine boreholes. Regardless of the degasification system employed, all mines have been able to recover large quantities of gas suitable for use in various applications. Following is a brief overview of the existing projects, arranged below by location. Table 3-1, at the end of this chapter, summarizes the major characteristics of the existing projects.

Alabama

Six mines in Alabama recover and sell methane: Blue Creek No. 3, Blue Creek No. 4, Blue Creek No. 5, Blue Creek No. 7, Oak Grove and Shoal Creek. The Blue Creek No. 3, No. 4, No. 5 and No. 7 mines are owned by Jim Walter Resources, while the Oak Grove Mine is owned by U.S. Steel Mining, and the Shoal Creek Mine is owned by Drummond Coal.

Jim Walter Resources (JWR):³

Blue Creek No. 3, No. 4, No. 5, and No. 7 Mines

Located in Jefferson and Tuscaloosa Counties, Alabama, the Jim Walter Resources mines are among the deepest and gassiest mines in the country. Opened in the early to mid-1970's, the mines cover an 80,000 acre area and have vertical shafts ranging from 1,300 to 2,100 feet in depth. The in-situ gas content of coal is about 500 to 600 cubic feet per ton and the total amount of methane liberated from these mines is estimated to be in excess of 2,500 cubic feet per ton of coal produced.

Jim Walter Resources (JWR) has been a leader in the development of coal mine methane recovery projects in the United States. The company's Blue Creek mines -- the Nos. 3, 4, 5,

¹ The project which includes Blacksville No. 1 is discussed in the "Pennsylvania" section of this chapter.

² Methane emissions may be converted to a measure equivalent to carbon dioxide, since methane is 21 times more potent than carbon dioxide over a 100 year time frame.

³ This description is a summary of information presented in two papers written by C.A. Dixon, Vice President of Mining Engineering, Jim Walter Resources. The two papers are "Coalbed Methane -- A Miner's Viewpoint," and "Maintaining Pipeline Quality Methane from Gob Wells." Full citations are included in reference section.

and 7 mines -- are currently recovering and selling approximately 40 million cubic feet of gas per day (Lasseter et al, 1996). Methane is produced using three recovery methods: 1) vertical degasification (holes drilled from the surface into the virgin coalbed); 2) horizontal degasification (holes drilled in the coalbed from active workings inside the mine); and 3) gob degasification program (holes drilled from the surface into the caved area behind the longwall faces).

In 1974, when the initial underground entries were being developed at the Blue Creek No. 3 Mine, extremely high levels of methane were encountered and it became apparent that the 800 HP ventilation fan that had been installed at the mine -- the largest fan of its kind at the time -- would not be able to sufficiently dilute the high quantities of methane that were being produced. Additionally, fans of a similar size had been planned for the even deeper and gassier Brookwood mines (Nos. 4, 5, & 7), at which ventilation shafts had already been installed. JWR became concerned that the extremely high cost of ventilating the new mines would render the mining uneconomic. A study performed by a consulting organization confirmed their fears. The study found that much greater quantities of air would be required than had initially been anticipated, which would require fans with much higher capacity volumes and pressures. Moreover, the analysis showed that, even with these larger fans, an economic rate of production could not be achieved without additional methods for removing large quantities of methane from the mine workings. Thus, a degasification system became an economic necessity in order to develop the mines.

During the same time period, an oil and gas production company that was interested in developing a commercial coalbed methane venture at the Blue Creek mines contacted JWR. Preliminary tests indicated that the Blue Creek coal seams would support a profitable methane project based on the gas prices at that time. A five-well test program was developed and each well was hydraulically fractured and dewatered. Hydraulic fracturing (which was done to stimulate methane liberation) was a major concern to JWR because of the potential to damage the coal seam. This concern proved to be unfounded, however, as the underground unit mined through the wells with no adverse effect on productivity. The successful five-well project was expanded to a thirty-well pilot project, which was also deemed to be a success. At that point, JWR and the oil and gas company decided to develop a full-scale coalbed degasification venture. An operating company, now known as Black Warrior Methane Corporation (BWM), was formed. BWM expanded the drilling program, negotiated a sales contract with a major natural gas distributor, and installed a transmission line from the gas field to the nearest interstate pipeline. By 1987, the vertical degasification program was producing approximately 6 million cubic feet per day of pipeline-quality gas from 75 active wells. By 1993, production from vertical wells was approximately 7 million cubic feet per day (20 percent of total production). JWR has continued to invest in this degasification technique.

In the late 1970's, JWR began a horizontal borehole degasification program. The program began as a joint project with the U.S. Bureau of Mines (USBM), which was interested in exploring the applicability of horizontal degasification. In October 1978, USBM technicians drilled a borehole to a depth of 1,010 feet from an active entry in the No. 4 Mine into an unmined area of the seam. The methane liberated from the seam was vented into the mine return airway. Methane production greatly exceeded expectations -- over 200,000 cubic feet per day was produced and 70,000 cubic feet per day was still being produced one year later. Moreover, the gas produced was over 99 percent methane. Methane levels recorded in mine working areas were substantially lowered, resulting in tremendous savings in ventilation costs and in a safer environment for the miners. Because of the great success of the initial joint JWR/USBM project, the horizontal degasification program was greatly expanded. Due to the high quality of the gas recovered, methane from the horizontal boreholes was no longer

vented, but was instead collected for sale along with gas from the vertical well degasification program. In 1989, the horizontal degasification program produced in excess of 4 million cubic feet per day from approximately 80,000 feet of boreholes. In 1993, production from the horizontal degasification program was also about 4 million cubic feet per day (10 percent of total production).

JWR continued to be at the forefront of developing degasification technologies when it became the first company to produce pipeline quality methane from gob wells. In January 1983, a longwall panel was drilled at the Blue Creek No. 4 Mine.⁴ Soon after, the first gob well was installed when it became evident that the large methane liberation created from the gob area behind the longwall face could not be cost-effectively handled by the existing ventilation system. The installation of the gob well resulted in a dramatic decrease in methane levels. Since then, the installation of gob wells has become a standard operating procedure at all the JWR mines. Typically, 2 to 3 gob wells are drilled for each longwall panel, though, depending on geologic conditions, a fourth well may be added to improve production. By 1989, JWR had drilled some 80 active gob wells

Gob wells had been in use at other mines, but JWR was the first company to produce pipeline quality methane from its gob wells. In general, methods used by JWR for installing gob wells and bringing them on-line is similar to the procedure used by other coal operations that do not utilize the methane. Large diameter holes are drilled from the surface to a point approximately twenty feet above the coal seam about one month in advance of longwall mining. The caving created by the advance of the longwall under the well results in substantial methane production. A compressor on the surface maintains a slight vacuum on the well, which is carefully monitored and regulated to ensure that oxygen levels do not reach unacceptable levels. An alternative venting system is also available so that if the well produces more gas than can be handled by the compressor or if the gas has been contaminated with too much mine air, a portion, or all of the gas may be discharged into the atmosphere. Experience has shown that the optimal operating range for each gob well is generally between 96 and 97 percent methane, which generally maximizes methane production, but still maintains a gas suitable for pipeline injection. With the large number of gob wells in operation, some can be producing at slightly below pipeline quality standards without jeopardizing the overall quality of the total gas produced. The nearly pure methane recovered from vertical wells and horizontal boreholes also helps to maintain the overall quality of the gas since the gas streams from various wells are blended together. Commercial production of gas from gob wells began in 1982

As with the vertical and horizontal programs, the gob well program has greatly improved safety conditions and has achieved tremendous savings in terms of the cost of ventilating the mine. JWR estimates that if the gob degasification system were not in effect, three additional ventilation shafts would be needed at a total cost of \$15 million. Furthermore, 7,000 additional HP would be needed at an operating cost of \$1.00 per ton of coal. Finally, many more underground airways would be required. Under current operating conditions, this would be neither technically nor economically feasible.

Over the years, JWR has been increasing the amount of methane that is recovered for pipeline sales. In 1993, JWR produced 33 mmcf/d. As of May 1996, there were 340 wells producing approximately 40 mmcf/d, with plans to develop as many as 100 additional wells

⁴ Longwall mining was already in use at the more shallow No. 3 mine, which was able to maintain safe methane levels through the use of its existing ventilation system.

over the next 12-18 months (Walter Industries Inc., 1996). The quantity of methane recovered in 1996 represents 46 percent of total methane liberated from the mines. Of the total recovered methane, vertical pre-mine wells are responsible for approximately 34 percent of production, gob wells are responsible for approximately 62 percent of production, and in-mine boreholes are responsible for the remaining 4 percent of production (Lasseter et. al., 1996). During the past two years, JWR has shifted toward a degasification program that emphasizes vertical pre-mine wells more heavily than had previously been the case. Each year, JWR develops 15 to 20 gob wells and about 50 vertical wells.

U.S. Steel Mining

Oak Grove Mine⁵

U.S. Steel Mining's (USM's) Oak Grove Mine produces methane for pipeline sales. USM is a subsidiary of USX, Incorporated (formerly U.S. Steel Corporation). Oak Grove is located in the east-central portion of the Black Warrior Basin of Jefferson County, Alabama. The target seam for mining is the Blue Creek bed of the Mary Lee coal group. The coal is mined at a depth of approximately 1,150 feet.

The effectiveness of a large-scale pattern of stimulated vertical wells in reducing the gas content of a coalbed was first demonstrated at the Oak Grove Mine. In 1977, a pattern of 23 coalbed methane vertical wells were drilled immediately east of the mine as part of a USBM pilot program to reduce methane-related mine hazards and to enhance mine productivity. The wells were drilled on a 1000-foot square grid (approximately 25-acre spacing). The program consisted of drilling a vertical well and hydraulically fracturing a single coal seam with a thickness of approximately 5 feet and an average gas content of 450 cubic feet per ton. Experimental production began in 1977, and most of the wells were producing by 1979. In the early 1980's, an additional 25 vertical wells were drilled east and south of the mine, yielding a total of 48 vertical wells operated by USM.

This was the first large-scale coal seam degasification project in the United States using vertical wells, as well as one of the first coalbed methane production projects. The work conducted during this program established the basic techniques for the drainage of coal seam methane using vertical wells. It also established a basis to determine the recoverability of methane. Based on samples obtained ten years apart (from coal desorption tests prior to methane drainage in 1977 and from samples taken in 1987 at the same location), 73 percent of the original gas in-place had been drained from the Blue Creek coal seam. After 10 years, the original wells had produced a total of 3.2 bcf (billion cubic feet) of methane that will never need to be controlled in the underground mine environment.

In addition to providing data about the percentage of gas that can be recovered from a vertical well program, data from the Oak Grove Mine have been valuable in determining the effects of hydraulic fracturing on the active mine. The impact of hydraulic fracturing on the integrity of the Blue Creek coal seam and the potential for mine roof damage was a major concern of USX's. Several wells were drilled and stimulated in the Blue Creek seam in advance of mining. Once mined through, the wells were mapped to determine any damage to the coal seam and/or surrounding strata. Based on the data from these wells, there have been no adverse effects on mining coal penetrated by the stimulated wells.

⁵ References used to develop this summary are Pashin (1991), Diamond (1993), GRI Quarterly (1993), and Briscoe et al. (1988). Production data is from the Alabama Oil and Gas Board.

In addition to the vertical wells drilled in advance of mining, Oak Grove Mine also has utilized both horizontal and gob wells for ventilation of methane, primarily to increase the safety of the underground mine. As of late 1994, a total of 24 horizontal wells have been drilled by USM. In contrast to the JWR mines, the greatest percentage of Oak Grove Mine's commercial gas production is from the vertical well program. Since the methane from the horizontal and gob wells is combined and sold in the same pipeline grid as the vertical wells, it is difficult to disaggregate the portion of gas produced by each method of degasification.

Since the late 1980's, several of the original 48 vertical wells drilled by USM have been shut in or have ceased commercial production. Through 1990, cumulative production from all of the Oak Grove Mine wells was 5.5 bcf. By 1995, the Oak Grove Mine's production was nearly 4.1 bcf of gas annually. In 1996, the Oak Grove Mine produced 9.3 mmcf/d, or an estimated 3.4 bcf of gas (Geomet, 1997a).

Oak Grove Degasification Field

The early success of the vertical methane drainage program at the Oak Grove Mine led to the drilling of a large number of commercial wells in the area. In 1980, the Alabama State Oil and Gas Board formally established the Oak Grove Degasification Field, including the mine and surrounding areas in Jefferson and Tuscaloosa Counties. Beginning in 1985, several companies, including Taurus Exploration and Amoco, launched an aggressive vertical methane well program after leasing significant acreage from USX's Oak Grove Degasification Field. In 1996, the Oak Grove Degasification Field produced 19.6 bcf of gas for pipeline sale (Alabama State Oil and Gas Board, 1997).

USM had drilled its original 48 vertical wells on a 40-acre spacing pattern, which allowed for removal of significant quantities of methane from the area to be mined. However, because the sole goal of other companies drilling in the Oak Grove Degasification Field is commercial methane production, rather than reducing emissions from future mining operations, most of the wells drilled since 1985 have been spaced on a 160-acre (or greater) pattern. While these wells do drain methane from the area to be mined, the wider well spacing does not drain the coal as effectively as would a true vertical pre-mine drainage program (U.S. Steel Mining Company, 1997).

Drummond Coal

Shoal Creek Mine

Drummond Coal's Shoal Creek Mine began producing coal in 1994. The mine entry is located in the Oak Grove Field, but mining will progress into the White Oak Field. Currently, Shoal Creek is using vertical pre-mine, horizontal and gob wells to drain methane. The pre-mine wells in the White Oak Field, operated by SONAT Exploration Co., produced more than 3.5 bcf in 1996, and currently produce about 22 mmcf of methane per day for pipeline sale. Drainage of methane from the White Oak Field is taking place at least five years in advance of mining. According to GeoMet Operating Co. (1997b), who is the contract operator of the project, about half of the property on which methane is currently being drained will eventually be mined, and ultimately, the project will degasify about one-third of the Shoal Creek Mine area. Numerous wells operated by Amoco in the Oak Grove Field are pre-draining methane from the Oak Grove side of the Shoal Creek Mine.

Colorado

There is one methane recovery and use project currently underway in Colorado. This project is taking place at the Golden Eagle Mine near Weston.

Golden Eagle Mine

The Golden Eagle Mine, owned by Basin Resources, has been closed since December, 1995.

In 1997, however, Stroud Oil Properties, Inc. began recovering methane from the mine's ventilation shafts and existing methane drainage boreholes. At present, Stroud is producing about 1.5 mmcf/d of methane from six boreholes (Stroud, 1997). They are currently expanding the project to include methane drainage from gob areas, and expect to increase gas production in the future. Stroud is marketing the gas through a company called NGTS, via the Colorado Interstate Gas pipeline system.

Ohio

There is one methane recovery and use project currently underway in Ohio. This project is taking place at the Nelms No. 1 Mine in Cadiz, Ohio, and also involves the Nelms-Cadiz Portal Mine, which is profiled in Chapter 6.

Nelms No. 1 Mine

Gas drained from the Nelms No. 1 Mine, which is permanently sealed, currently supplies a power generation project developed by Northwest Fuel Development, Inc. Northwest Fuel owns the coalbed methane lease at the mine and operates the power plant. The project uses internal combustion engines to generate 500 kW of electricity, which is sold to the adjacent Nelms-Cadiz Portal Mine. The project employs seven engines, each using 25,000 cf of 960-980 Btu gas per day (Northwest Fuel, 1997). In the future, the project will expand to an additional 500 kW of electric output. A fuel cell demonstration project at the Nelms No. 1 Mine is also being planned.

Concurrently, Northwest Fuel Development, Inc. is researching and developing a gas enrichment project at the Nelms No. 1 Mine. The company is testing a pressure swing adsorption process that will separate carbon dioxide and nitrogen from methane. This enrichment process will result in gas that is of pipeline quality. Should the tests be successful, current projections are that gas sales will be 200 to 2000 mcf/d. For the gas production project, Northwest Fuel will install the pressure swing adsorption equipment, while LAHD Energy will install the pipelines.

Pennsylvania

There is one methane recovery and use project underway in Pennsylvania. The project involves four mines owned by Consolidation Coal Company. Because the main portals for these mines are in West Virginia, they are categorized as West Virginia mines in Chapter 6 (the individual mine profiles section of this document). However, significant sections of three

of the mines extend into Pennsylvania, and the majority of the gas produced is from Pennsylvania, therefore this methane recovery and use project is classified as a Pennsylvania project.

Consolidation Coal Company (a subsidiary of the CONSOL Coal Group)

Blacksville Nos. 1 and 2, Humphrey No. 7, and Loveridge No. 22 Mines

EnviroGas Recovery Inc., and CBE Inc., are undertaking a gas enrichment and sales project at the Blacksville No. 1 Mine (which is closed), the Blacksville No. 2 Mine, the Humphrey No. 7 mine and the Loveridge No. 22 Mine (CBE, 1997). Currently, some of the gas recovered from these mines meets pipeline specifications without enrichment, and in 1997 these mines began selling gas directly to the pipeline. However, the enrichment project underway will increase the volume of gas that can be sold. The project will capture as much gas as possible from these mines, and will remove carbon dioxide, oxygen and nitrogen from the gas using catalytic, amine and cryogenic processes respectively. Columbia Energy Services will purchase the resulting pipeline-quality gas. Phase I of the enrichment plant is under construction, and when completed will be able to process 5-6 Mmcfd of gas whose methane content (prior to enrichment) is about 80-85%. When Phase 2 of the project is completed, it is anticipated that the plant will be able to process 10-12 mmcf/d.

Virginia

The commercial potential of coalbed methane recovery in Virginia has long been recognized, but complicated issues regarding gas ownership, as well as the lack of pipeline capacity in southwest Virginia, delayed commercial coalbed methane recovery in this area until the early 1990's. In 1990, in cooperation with both the oil and gas industry and the coal industry, the State of Virginia passed legislation to encourage commercial coalbed methane development (1990 Virginia Code Section 45.1-361.22). Subsequently, in October 1991 the Virginia Department of Oil and Gas issued new regulations governing coalbed methane development. Following the adoption of these regulations, construction began on a 47-mile long trunk pipeline connecting the coalbed methane fields in southwest Virginia to an interstate transmission line in West Virginia operated by Columbia Gas Transmission System. Completed in early 1992, this trunk line was a joint development between Conoco, Inc., OXY USA, Inc. (a wholly owned subsidiary of Occidental Petroleum Corp.), and Consolidation Coal (a wholly owned subsidiary of CONSOL). Gas sales began that same year.

There are three methane recovery and use projects currently underway in Virginia. These projects are taking place at the following mines: Buchanan No. 1, VP No. 3, and VP No. 8. The CONSOL Coal Group owns all three mines.

CONSOL

CONSOL recovers methane from three of the gassiest mines in the southwestern region of Virginia: Buchanan No. 1, VP No. 3, and VP No. 8. One of these mines, VP No. 8 was born out of the consolidation of the VP No. 5 and VP No. 6 mines. Prior to July 1993, the VP No. 3, VP No. 5, and VP No. 6 mines were owned and operated by Island Creek Coal, a subsidiary of Occidental Petroleum. In July of 1993, CONSOL acquired Island Creek Corporation from Occidental Petroleum Corporation. This purchase included Island Creek's VP mines in Buchanan County, Virginia and the associated coalbed methane properties. CONSOL had operated the adjacent Buchanan No. 1 Mine since 1983. Each company had developed extensive degasification programs on their respective properties (see below). Since the acquisition, all coal and coalbed methane operations have been solely conducted by CONSOL. In 1994, the VP No. 5 and No. 6 mines were combined to form a single mine, the VP No. 8 Mine (Coal Outlook 7/18/94).

In late 1995, MCN Investment Corporation (MCNIC) acquired certain gas producing and pipeline properties in Virginia from CONSOL. The acquisition included a 100 percent interest in 130 producing wells, and rights to undertake additional development drilling on approximately 100,000 acres of Virginia coalbed methane properties. The acquired property contains in excess of 190 bcf of proven gas reserves. The transaction also included approximately 80 miles of gathering lines and a 50 percent interest in a 40-mile major gathering line connecting these and other gas reserves to the Columbia Gas transmission pipeline system. A portion of current production from wells drilled prior to January 1, 1993 qualifies for federal income tax credits of about \$1 per Mcf (MCN Web Page and 1996 10-K Report). CONSOL has stated that the reserves sold are those associated with the Buchanan No. 1, VP No. 3, and VP No. 8 mines (see individual mine profiles).

CONSOL continues to invest in vertical pre-mine wells, although only approximately 22 percent of gas produced is via this method. Although more gas can be successfully drained if a vertical pre-mine well has been in place for a long period, CONSOL has been opting for an advance drainage time frame that adequately balances the risk of investing in a vertical pre-mine drainage system with that of the company's mining plans. Thus, the company uses a three to five year advance degasification program to the extent that this can be feasibly coordinated with the company's overall mining strategies.

CONSOL continues to increase gas production and to reduce the amount of methane that is emitted to the atmosphere. Currently, CONSOL produces gas for pipeline sales and on site use from three mines: Buchanan No. 1, VP No. 3, and VP No. 8. The total methane drained at the three CONSOL Virginia mine properties equaled or surpassed 73 mmcf/d in 1996 (Virginia Gas and Oil Board, 1997a; CONSOL, 1997) and increased to 85 mmcf/d in 1997 (CONSOL, 1997). This number significantly exceeds ventilation emissions of 32.9 mmcf/d, which indicates that much of the produced gas comes from virgin coals that CONSOL may mine in the future, and/or that recovery efficiencies are higher than standard EPA assumptions.

Of the 85 mmcf/d of methane that CONSOL currently recovers, a small fraction, approximately 1.5 mmcf/d, is being used on-site in a thermal dryer. The remaining amount is sold to a pipeline. Of the total recovered methane, gob wells account for approximately 65 percent of production, vertical wells account for approximately 22 percent of production, in-mine boreholes account for 3 percent of production, and releases from sealed areas account for the remaining 10 percent of production. Recently, pipeline capacity in southwestern Virginia was increased, making increased recovery of methane feasible for CONSOL. CONSOL reacted to

this development by installing additional compression capability to handle the increased gas flow (CONSOL, 1997).

Recently, CONSOL reported its methane emissions and emissions reductions as part of the Department of Energy's 1605(b) voluntary reporting of greenhouse gas emissions program. CONSOL reports that methane emissions have decreased from 1.5 million tons in 1990 to 923,000 tons in 1995. Methane emissions reductions rose from 98,973 tons in 1992 to 332,995 tons in 1993, an increase attributed to CONSOL's purchase of the Island Creek mines and the company's inclusion of the Island Creek mines' methane emissions reductions with their own. Methane emissions reductions continued to rise to 640,047 tons in 1994, which CONSOL attributed to increased methane recovery from the company's mines. In 1995, the company reported methane emissions reductions of 580,372 tons. Though slightly lower than those reported in 1994, this was probably a result of normal operating practices rather than any major changes in the recovery program.

Buchanan No. 1 Mine

A deep and gassy mine, Buchanan No. 1 is actively mining at a depth of about 1,500 feet and has an in-situ gas content of about 600 cf/ton (Morgan, 1994).⁶ Degasification efforts at the Buchanan No. 1 Mine began in 1984 when the first vertical wells were drilled and fractured. These first wells were mined-through three years later, in 1987. Injection wells are used to handle the water produced from the vertical wells.

Beginning in May 1995, Buchanan No. 1 began using recovered methane, instead of coal, as fuel in its thermal dryer. As of May 1997, the thermal dryer was consuming approximately 1.5 mmcf/d, or 547.5 mmcf/year (CONSOL, 1997).

VP No. 3 and VP No. 8 Mines

In the late 1960's, it became apparent to Island Creek that coal production from these newly opened mines was being severely limited by methane liberation both in mine development and in the retreating longwall units (Kalasky et al., 1979). The in-situ gas content of the Pocahontas No. 3 coal seam in that area exceeded 600 cubic feet per ton. The total amount of methane emitted from some of these mines (e.g., Beatrice, VP No.'s 1-2) exceeded 3,000 cubic feet per ton of coal mined. The first gob wells were drilled in 1970. Initially, 6-inch and 7-inch diameter holes were drilled to a level a few feet below the Pocahontas No. 3 coalbed. These holes were drilled to vent methane stored in the overburden strata and mobilized by the caving process behind the longwall face. Without properly spaced holes, reservoir pressure forces gas down into the mine works. This condition frequently led to methane concentrations above permissible limits in the mine ventilation air, which in turn caused idling of the coal production operation until the methane levels were once again diluted to safe levels. To enhance the flow of gas from the longwall gob, single stage centrifugal blowers were installed on the holes (Moore and Zabatakis, 1972). The blower imposed a forced draft on the natural flow conditions of the hole and tended to draw mine ventilation air into the gas stream, lowering its quality. Gas quality was of no concern at the time, since the gas was removed solely to improve underground safety and to increase mining productivity. With increasing

⁶ The source of the information contained in this paragraph is a presentation given by Claude Morgan of CONSOL, Inc. at the North American Coalbed Methane Forum (Pittsburgh, PA, April 11-12, 1994).

longwall retreat rates and increasing longwall panel dimensions, the size and number of wells per longwall panel was gradually increased over the year, to accommodate higher methane liberation rates and to minimize down-time during longwall production due to high methane concentrations underground. Holes typically were completed with a 9-inch or 11-inch diameter up to 50 feet above the mining horizon, and equipped with 7 stage centrifugal blowers requiring 125 or 250 HP motors, depending on the pump size.

In 1977, Island Creek began a horizontal borehole program under a cost-sharing contract with the U.S. Department of Energy (von Schonfeldt et al. 1980). In-seam holes (horizontal holes) of up to 4,000 feet in length were completed to demonstrate the feasibility of draining methane from the coal seam in advance of mining. Island Creek has used horizontal methane drainage holes in longwall panels have been used at Island Creek since 1986. Drilled for the purpose of enhancing mine safety, these holes have over the years significantly improved longwall mining productivity by reducing "gas-offs" in the face area and returns during mining operations (Aul et al.). A fail-safe underground piping system helped move the gas produced from the horizontal holes to the surface where it was vented. Up to 1 bcf of methane per year was drained from the seam through horizontal boreholes.

By the end of 1991, Island Creek had developed technology to produce pipeline-quality gas from its gob wells, which made it possible to recover methane from the time a well was under-mined until the time production had fallen to uneconomically small volumes. The production technology is similar to that described above for Jim Walter Resources. Island Creek remotely monitored and controlled gas quality and essential operating parameters on all wells tied to a sales pipeline, enabling them to operate their gob wells from one central location on a 24 hour per day basis. In addition, the methane content in certain underground ventilation air returns was also monitored remotely to ensure underground mine safety at all times. Island Creek recovered gas from horizontal boreholes and brought it to the surface through strategically placed vertical boreholes in a similar fashion.

Gas sales started in May 1992 at a rate of 3 mmcf/d. Over the next twelve months, production had grown to more than 30 mmcf/d (about 11 bcf per year). Today, as in the past, the former Island Creek property produces gas primarily via three methods:

- Vertical wells, drilled and hydraulically stimulated much like conventional gas wells. CONSOL completes these wells in the virgin Pocahontas No. 3 coalbed and certain coal seams in the overburden;
- Horizontal boreholes, drilled from underground into longwall panels; and
- Gob wells, which CONSOL drills over longwall panels producing gas from the caved zone behind the longwall face.

Additionally, CONSOL recovers methane from abandoned areas at the VP and Buchanan mines. Once they complete a methane drainage program from an abandoned area, that area is sealed, and no further methane extraction takes place (CONSOL, 1997).

West Virginia

There are two methane recovery and use projects currently underway in West Virginia⁷. These projects are taking place at the Federal No. 2 and Pinnacle No. 50 mines. The Federal No. 2 Mine is owned by Peabody Coal and the Pinnacle No. 50 Mine is owned by U.S. Steel Mining.

Eastern Associated Coal (Peabody)

Federal No. 2 Mine

Federal No. 2 currently drains methane using vertical gob wells. The mine markets gas recovered from some higher quality gob wells to a natural gas pipeline. This gas project is a joint venture with Columbia Natural Gas Producing Company (CNGP). According to the Department of Energy's 1605 (b) voluntary reporting program, in 1994, the mine recovered more than 121.8 mmcf of methane for pipeline sale (EIA, 1996). Methane recovery increased in 1995 to about 189 mmcf (CNGP, 1997). The recovery project at Federal No. 2 continues to expand.

Eastern Associated Coal and Northwest Fuel Development are involved with CNGP in a Department of Energy funded effort to evaluate the use of an integrated power generation system comprised of IC engines and gas turbines (Northwest Fuel, 1997). This combination of equipment will allow low quality and variable quality gob gas to be used as a fuel. The electricity produced will power CNGP's existing coalbed methane pipeline injection operations at the mine site. A generation capacity of 1.2 MW is planned.

The Federal No. 2 power project will build upon an aggressive coalbed methane degasification and commercialization project that likely will involve in-seam horizontal boreholes, gob wells, and vertical pre-mine wells.

U.S. Steel Mining

Pinnacle No. 50 Mine

USM's Pinnacle No. 50 Mine, located in West Virginia, produces methane for pipeline sale. Currently, the mine sells recovered coal mine gas to a local pipeline company. The mine uses a horizontal borehole drainage system. In 1996, the Pinnacle Mine recovered and sold approximately 506 million cubic feet of gas, up from the previous year when the mine recovered and sold approximately 345 million cubic feet of gas (West Virginia Office of Oil and Gas, 1997).

Noumenon Corporation

Unspecified Mines in West Virginia

The Noumenon Corporation of Core, West Virginia, blends gas from coal mines in northern West Virginia with propane or natural gas in order to increase the quality to pipeline specifications (approximately 1000 Btu). This gas is recovered from both active and closed mines (the names are confidential). This project began in 1990, when the primary customer for the gas was a glass factory in Morgantown, West Virginia. The project has since expanded, and Noumenon now sells blended coal mine gas to five different utilities (Shuman, 1997).

⁷ Another project involving four West Virginia mines is discussed under the "Pennsylvania" section earlier in this chapter, for reasons explained in therein.

Summary

Table 3-1 summarizes the methane recovery and use projects discussed in this chapter.

Table 3-1: Summary of Existing Methane Recovery and Use Projects

Mine Name	Mine Location (State)	Approximate Amount of Gas Used in 1996 ¹	Methane Use Option	Notes
Blue Creek No. 3 Blue Creek No. 4 Blue Creek No. 5 Blue Creek No. 7	Alabama	40 mmcf/day	Pipeline Sales	The four mines collectively produced 40 mmcf/day of gas in 1996.
Oak Grove	Alabama	9.3 mmcf/day	Pipeline Sales	
Shoal Creek	Alabama	9.7 mmcf/day (22 mmcf/day in 1997)	Pipeline Sales	Includes some stand-alone production, therefore, not all production will lead to emissions reduction
Golden Eagle	Colorado	0 (1.5 mmcf/d in 1997)	Pipeline Sales	The project began in 1997.
Nelms No. 1 ²	Ohio	0.175 mmcf/day	Power Generation, Pipeline Sales (planned)	Nelms No. 1 is permanently sealed and is not profiled. However, the adjacent Nelms-Cadiz Portal Mine, which purchases power generated by methane from Nelms No. 1, is profiled.
Buchanan No. 1 VP #3 VP #8	Virginia	73 mmcf/day (85 mmcf/day in 1997)	On-Site Use Pipeline Sales	These three mines collectively produced 73 mmcf/day of gas in 1996. A small portion (1.5 mmcf/d) of the total gas gas production is used on-site in a thermal dryer.
Blacksville No. 1 ² Blacksville No. 2 Humphrey No. 7 Loveridge No. 22	West Virginia (but most of the gas is from seams in Pennsylvania)	0	Pipeline Sales	These four mines comprise one methane recovery project, which began in 1997.
Federal No. 2	West Virginia	0.5 mmcf/day (as of 1995)	Pipeline Sales, Power Generation (planned)	Project continues to expand, but 1996 data are not publicly available.
Pinnacle No. 50	West Virginia	1.39 mmcf/day	Pipeline Sales	
Unspecified Mines	West Virginia (northern)	NA	Pipeline Sales	The names of the mines at which this project is taking place are confidential.
NA means not available report ¹ Unless otherwise specified ² Mine not profiled in this				

4. A Key to Evaluating Mine Profiles

4. A Key to Evaluating Mine Profiles

This report contains profiles of coal mines that are candidates for the development of methane recovery and use projects. Also included are mines that already have installed methane recovery and use systems. The mines that are profiled were selected primarily on the basis of their annual methane emissions from ventilation systems as recorded in a Mine Safety and Health Administration database (MSHA, 1997a; USDOE, 1996b). While this report is thought to contain a comprehensive listing of the best candidates for cost-effective methane recovery projects, it is possible that some promising candidate mines have not yet been identified.

The mine profiles presented in this report are designed to assist interested parties in identifying mines that can sustain a profitable methane recovery and use project. Each mine profile is comprised of the following sections: geographic data, corporate information, mine address, general information, production and emissions data, potential energy and environmental reductions data, power generation potential data, pipeline sales potential data, other utilization possibilities, and a summary of recent news. The mine profiles are ordered alphabetically by state, then by mine name.

Following this chapter are summary tables that list key data elements shown in the mine profiles. Summary Table 1 lists all profiled mines in alphabetical order. The individual mine profiles follow the summary tables.

Operating Status

Each mine's operating status as of August 1997 is listed at the top right-hand corner of each profile. The operating status may be listed as described below:

Operating: These mines are currently producing coal.

Idle: A mine that is open but not currently producing coal.

Closing or Closed: If a mine is in the process of being closed it is categorized as "closing." If a mine has stopped producing coal it is categorized as "closed." This report includes profiles of mines that are closing or have recently been closed, not only because of the possibility that coal production may resume in the future, but also because successful methane recovery projects can be initiated at closing/closed mines.

Open/Using, Closed/Using, Closing/Using, or Idle/Using: If there is an established methane recovery and use project in place at a mine, and the mine is operating, closed, closing, or idle, the mine is classified as "open/using," "closed/using," "closing/using," or "idle/using," respectively.

The current operating status was determined by reviewing coal industry publications that track the production status of coal mines, and through discussions with MSHA district offices and sources in the coal industry. Summary Table 2 shows the operating status, as of August 1997, of the mines profiled in this report.

Geographic Data

The first section of each profile gives the geographic location of the mine, including the state, county, coal basin where the mine is located, and the coalbed(s) from which it produces coal. The sources for this information were MSHA (1997) and the Keystone Coal Industry Manual (Keystone, 1997).

State: Mines included in this report are located in the following states -- Alabama, Colorado, Illinois, Indiana, Kentucky, New Mexico, Ohio, Pennsylvania, Utah, Virginia, or West Virginia. Summary Table 3 shows the mines listed by state.

County: A relatively small number of counties contain a majority of the gassy mines in the country. Summary Table 3 shows the mines listed by state and by county.

Coal Basin: Mines are located in one of five major coal producing regions: the Black Warrior Basin, the Central Appalachian Basin, the Northern Appalachian Basin, the Illinois Basin, or one of the "Western basins" (Canon City Field, Piceance Basin, Raton Mesa, or Uinta Basin), which are located in the states of Colorado, Utah and New Mexico. Major geological characteristics of coal seams, including methane content, sulfur content, depth, and permeability tend to vary by basin. Summary Table 4 lists the mines by basin and 1996 estimated specific emissions per ton of coal mined.

Coalbed: Substantial and detailed information has been published on the geological and mining characteristics of major coalbeds occurring in the U.S. Summary Table 5 lists mines according to the seam from which they produce their coal.

Corporate Information

Current Owner: Current owner refers to the mining company that owns the mine. Summary Table 6 lists mines by mining company. The sources for this information were the MSHA database and the Keystone Coal Industry Manual (Keystone, 1997).

Parent Company: Many coal companies are owned by a parent company. In addition to showing the coal companies, Summary Table 6 also shows the parent corporation of the mining company. This information was taken from Keystone (1997) and EIA (1993 - 1995).

Previous Owner: The name of any previous mine owners is useful as some of the coal mines profiled here have had numerous owners. This information, along with the previous or alternate name of the mine, is based on previous editions of the Keystone Coal Industry Manual.

Previous or Alternate Name: Mines frequently undergo name changes, particularly when they are purchased by a new company. This section lists previous or alternate mine names.

Mine Address

This section includes the phone number and mailing address of the mine and a contact name.

The principal source of this information was the Keystone Coal Industry Manual. The phone numbers and mailing addresses are believed to be current. The contact names, however, may be somewhat out of date because the most recent editions of the Keystone Coal Industry Manual have not included this information for all of the mines.

General Information

Number of Employees: This field shows the number of people employed by the mine, as reported in the Keystone Coal Industry Manual. The number of employees reflects the latest year for which data were available. In some cases, the data are from the early 1990's, because the number of employees at the mine was not included in more recent editions of the Keystone Coal Industry Manual. For mines that are categorized as closed, the profile lists the number of persons employed by the mine when it was operating.

Year of Initial Production: Year of initial production indicates the age of the mine, as reported in the Keystone Coal Industry Manual.

Life Expectancy: For obvious reasons, life expectancy is an important factor in determining whether a mine is a good candidate for a methane recovery and use project. Information on life expectancy was collected from various Keystone Coal Industry Manuals. Given the difficulty in predicting mine life, however, this statistic is perhaps only marginally useful.

Prep Plant Located On Site: The profile indicates whether a preparation plant is located at the mine, based on the Keystone Coal Industry Manual's and *Coal* magazine's annual prep plant surveys. At the preparation plant, coal is crushed, cleaned and dried. Most large mines have a prep plant located within close proximity. In some cases, a prep plant will process coal not only from the on-site mine, but also from other nearby mines. Information regarding whether the mine has a prep plant, and the amount of coal processed, is of importance in determining the mine's total electricity and fuel demands.

Mining Method: Mines are classified as longwall or room-and-pillar, based on *Coal* magazine's annual longwall survey and on information in coal industry publications. The mining method used is important for several reasons. First, longwall mines tend to emit more methane than do room-and-pillar mines, as the longwall technique tends to cause a more extensive collapse of the methane-rich strata above the coal seam. Furthermore, longwall mining has higher up-front capital costs. Thus, a company is not likely to invest in a longwall at a mine that is not expected to have a fairly long life. Finally, while room-and-pillar mining is the more common method, the number of longwall mines is growing. In fact, the longwall technique seems to be the preferred mining method at the largest and gassiest mines. Summary Table 7 lists mines by mining method.

Primary Coal Use: Coal may be used for steam and/or metallurgical purposes. Steam coal is used by utilities to produce electricity, while metallurgical coal is used to produce coke. The primary coal use is based on information in the Keystone Coal Industry Manual. Summary Table 8 lists mines by primary coal use.

Sulfur Content: With the onset of the acid rain provisions of the Clean Air Act Amendments (CAAA) of 1990, the sulfur content of coal may be an important indicator of a mine's future economic status. For example, according to a series of reports published by the Illinois Coal Development Board (ICDB, 1991 to 1994), several high sulfur Illinois mines have already closed as a result of the CAAA, and several others will likely close as their existing utility contracts expire. The coal sulfur content varies for a given mine due to variations within the coal seams being mined. Thus, sulfur content is presented as a range. Sulfur content data were gathered from various Keystone Coal Industry Manuals. Summary Table 9 lists the coal mines and the sulfur content of the coal that is sold from these mines, beginning with the mines that have a relatively low sulfur content.

Btus/lb: Btus (British Thermal Units) per pound of coal produced indicates the heating value of the coal. This statistic, which was taken from the Keystone Coal Industry Manual, is used in comparing the energy value of the coal to the energy value of the methane recovered (see section on Environmental and Energy benefits below).

Production, Ventilation and Drainage Data

This section presents the quantity of methane emitted from, and the amount of coal produced by, the profiled mines for each of the years 1993 to 1996.

Coal Production: Most of the mines profiled in this report are large, with production exceeding one million tons per year. Annual coal production is an important factor in determining a mine's potential for profitable methane recovery. Generally, larger mines will be better candidates because of the potential for high methane production and because they are more likely to be able to finance the large capital investments required for a methane recovery and utilization project. Coal production was based primarily on annual Energy Information Administration (EIA) reports, but was supplemented with data from coal producing states. Summary Table 10 lists the coal mines by the amount of coal they produced in 1996, while Table 11 lists the coal mines by the amount of coal they produced in 1995.

Drainage System Used: Twenty-five of the mines profiled in this report use some type of drainage (or degasification) system to capture coal mine methane. Drainage systems used include vertical pre-mine (drilled in advance of mining), vertical gob wells, long-hole horizontal pre-mine, and horizontal pre-mine. Summary Table 12 lists mines by drainage system used.

Estimated Total Methane Liberated: Methane liberation is the total volume of methane that is removed from the mine by ventilation or drainage. Liberation differs from emissions in that the term emissions, as used in this report, refers to methane that is not used and is therefore emitted to the atmosphere. Estimated total methane liberated is the sum of "emissions from ventilation systems" and "estimated methane drained." For mines that do not use or sell any of their methane, estimated total methane liberated equals estimated methane emissions to the atmosphere. The volume of methane liberated is shown for the years 1993, 1994, 1995 and 1996. Summary Table 13 shows mines listed by their estimated total daily methane liberation for 1996.

Emissions from Ventilation Systems: Methane released to the atmosphere from ventilation systems is emitted in very low concentrations (typically less than one percent in air). MSHA field personnel test methane emissions rates at each coal mine on a quarterly basis (MSHA, 1997b). Testing is performed underground at the same location each time. However, MSHA does not necessarily conduct the tests at precise three-month intervals, nor are they always

taken at the same time of day. In some instances, if the mine is confident its own ventilation emissions measurements are satisfactory, MSHA will accept these data rather than performing a test. The ventilation emissions data for a given year are therefore averages of the four quarterly tests, and are accurate to the extent that the data collected at those four times are representative of actual emissions. Summary Table 14 lists the mines by their 1996 ventilation emissions, based on MSHA data.

Estimated Methane Drained: Mines that employ degasification systems emit large quantities of methane in high concentrations. Summary Table 15 lists mines according to the estimated methane drained. In contrast to ventilation emissions, no agency requires mines to report the amount of methane they drain, and actual methane drainage data are therefore unavailable. Therefore, EPA has estimated the volume of methane drained based on estimated drainage efficiency, as defined below. Based on information obtained from MSHA district offices, EPA has developed a list of 23 U.S. mines that have drainage systems in place. A list of the mines that have drainage systems is shown in Summary Table 12. For the purpose of estimating emissions from drainage systems, if a mine is listed as having a drainage system in place, it is assumed that the system was in place from 1993 onward.

Estimated Current Drainage Efficiency: In order to estimate the amount of methane emitted at mines that are believed to have drainage systems, it was assumed that these emissions would represent 40 percent of total methane liberation from the mine. Thus, for mines that have drainage systems, ventilation emissions were assumed to equal 60 percent of total liberation, with emissions from drainage systems accounting for the remaining 40 percent. For mines that do not already have drainage systems in place, ventilation emissions are assumed to equal 100 percent of total methane liberation.

The assumption that methane drainage accounts for 40 percent of total methane liberation is probably conservative for some mines, but optimistic for others. At the Jim Walter Resources mines in Alabama, methane drainage emission accounts for about 46 percent of total liberation (the ratio of drainage to ventilation emissions is known because these mines recover methane from their drainage systems for sale to a pipeline). However, at CONSOL's mines in Virginia, drainage is estimated to average at least 53 percent of total liberation, while at other mines, the drainage efficiency can be less than 15 percent. Accordingly, the drainage efficiency of 40 percent is merely an arbitrarily chosen value, and may not reflect actual conditions at all mines.

Specific Emissions: "Specific emissions" refers to the total amount of methane liberated per ton of coal that is mined. Specific emissions are an important indicator of whether a mine is a good candidate for a methane recovery project. In general, mines with higher specific emissions tend to have stronger potential for methane recovery. Summary Table 16 shows a list of mines ordered according to specific emissions. Note that the coal production and methane liberation values shown in this report have been rounded, whereas the data actually used to calculate the specific emissions values have not been rounded. Therefore, the specific emissions data shown in this report may differ from results that the reader would obtain by dividing the methane liberation values by the coal production values. This difference is strictly due to rounding, and does not reflect any error in calculation.

Energy and Environmental Value of Emissions Reduction

This section presents information on the environmental and energy benefits that may be achieved by developing a methane recovery project at a mine.

CO₂ Equivalent of CH₄ Emissions Reductions (mmt/yr). This statistic shows the carbon dioxide (CO₂) equivalent of the *annual* methane emissions reductions that may potentially be achieved at each mine. The CO₂ equivalent of the potential methane emissions reductions is shown in order to facilitate the comparison of the environmental benefits of coal mine methane recovery projects to other greenhouse gas mitigation projects. The potential quantity of methane that may be recovered from a mine -- which represents the emissions reductions that may be achieved -- is converted to a CO₂ equivalent as follows:

$$\text{CO}_2 \text{ equivalent (million tons/yr)} = \frac{[\text{CH}_4 \text{ liberated (mmcf/yr)} \times \text{recovery efficiency (40\% or 60\%)} \times 19.2 \text{ g CH}_4/\text{cf} \times 21 \text{ g CO}_2/1 \text{ g CH}_4 \times 1 \text{ lb} / 453.59 \text{ g} \times 1 \text{ ton} / 2000 \text{ lbs}]}{1}$$

where: 21 is the global warming potential (GWP) of emitting 1 gram of methane compared to emitting 1 gram of carbon dioxide over a 100 year time period¹

19.2 g/cf is the density of methane at 60 degrees F and atmospheric pressure

The CO₂ equivalent is shown assuming both a 40% and a 60% recovery efficiency (i.e., the portion of total methane emissions that are recovered and utilized). Summary Table 17 shows the CO₂ equivalent of the potential methane emissions reductions that may be achieved at each mine.

CO₂ Equivalent of CH₄ Emissions Reductions/CO₂ Emissions from Coal Combustion: This ratio shows the impact on global warming resulting from reducing methane emissions, in comparison with the impact on global warming resulting from reducing CO₂ emissions from the combustion of coal produced at the mine. The ratio is calculated by converting the methane recovered into a CO₂ equivalent (as described above) and dividing by the annual CO₂ emitted from the combustion of coal produced at the mine. In order to calculate the CO₂ emissions from coal combustion, the annual coal production is multiplied by the Btu value of the coal (see general information section for Btu value). Next, this value is multiplied by an emissions factor of from 203 to 210 lbs CO₂ per million Btu.² Finally, the value is multiplied by 99 percent to account for the fraction oxidized. The formula is as follows:

$$\frac{[\text{CO}_2 \text{ equivalent of potential annual CH}_4 \text{ emissions reductions (lbs)}]}{[\text{annual coal production (tons)} \times \text{Btus/ton} \times \text{lbs CO}_2 \text{ emitted} / \text{Btu} \times 99\% \text{ (fraction oxidized)}]}$$

The ratio is calculated assuming both a 40% and a 60% recovery efficiency.

Btu Value of Recovered Methane/Btu Value of Coal Produced: In order to calculate this ratio, the potential annual quantity of methane recovered is multiplied by a value of 1000 Btus/cf. Annual coal production is multiplied by the Btus/ton value for the mine. The ratio of the energy value of the methane recovered to the energy value of the coal produced is then calculated. The formula is as follows:

¹ For further information on the global warming potential of various greenhouse gases see Intergovernmental Panel on Climate Change (1992) and EPA (1993a and 1993b)

² The emissions factor used is based on average state values reported in Energy Information Administration (1992). For the states examined in this report, values range from about 203 to 210 lbs CO₂/mm Btu.

$$\frac{[\text{Recovered methane (cf/yr)} \times 1000 \text{ Btus/cf}]}{[\text{coal production (tons)} \times \text{Btus/ton}]}$$

As with the other statistics in this section, the ratio is calculated assuming both a 40% and a 60% recovery efficiency. In comparison with the first ratio (CO₂ equivalent of methane/ CO₂ emissions from coal combustion), the energy value of the methane emissions is a much smaller fraction of the energy value of the coal production.

Power Generation Potential

This section presents data relevant to the examination of whether the mine is a good candidate for an on-site electricity generation project.

Utility Electricity Supplier: The utility that supplies electricity to the mine is listed here, based on the service areas reported in the *Directory of Electrical Utilities* (Electrical World, 1993). Summary Table 18 lists the utilities that sell power to the profiled mines.

Parent of Utility: The parent company of the local electric utility is also shown. This information is also based on the *Directory of Electrical Utilities* (Electrical World, 1993).

Electricity Demand (MW): The annual electricity demand -- including the electricity demands of the mine plus the additional electricity load of the preparation plant -- is calculated as follows:

Mine Electricity Demand Assumptions:

Total annual electricity needs are estimated by assuming that 24 kwh are needed for each ton of coal mined.

Ventilation systems are run 24 hours a day, 365 days a year (8760 hours a year) and account for about 25% of total electricity needs.

Other mine operations run 16 hours a day for 220 days a year (3520 hours a year) and account for 75% of total electricity needs

Demand (kwh/yr): 24 kwh/ton x tons mined/yr = kwhs/yr

Demand (kW): $\frac{[(75\% \times \text{kwhs/yr}) / (3520 \text{ hours})]}{(\text{mine operations})} + \frac{[(25\% \times \text{kwhs/yr}) / (8760 \text{ hours})]}{(\text{mine ventilation})}$

Prep Plant Electricity Demand Assumptions:

Prep plants require 6 kwh/ton of coal processed

Prep plants are operated 16 hours a day, 220 days a year (3520 hours)

Demand (kwh/yr): 6 kwh/ton x tons/year

Demand (kW): [kwh/yr / 3520 hours]

Electricity Demand (GWh/year): The annual continuous electricity demand -- including the electricity demands of the mine plus the additional electricity load of the preparation plant -- is calculated as follows:

Mine Electricity Demand Assumptions:

Total annual electricity needs are estimated by assuming that 24 kwh are needed for each ton of coal mined.

Demand (kwh/yr): $24 \text{ kwh/ton} \times \text{tons mined/yr} = \text{kwhs/yr}$

Demand (GWh/year): $[\text{Demand (kwh/yr)}] / 10^6$

Prep Plant Electricity Demand Assumptions:

Prep plants require 6 kwh/ton of coal processed

Demand (kwh/yr): $6 \text{ kwh/ton} \times \text{tons/year}$

Demand (GWh/year): $[\text{Demand (kwh/yr)}] / 10^6$

Potential Electric Generating Capacity (kW): The potential electric generating capacity (i.e., the amount of electricity that could be generated from recovered coal mine methane) is estimated by assuming that there are 1000 Btus/cf of methane recovered and that the heat rate of a generator would be about 11,000 Btus/cf, which is a conservative assumption for a heat rate given that a gas turbine would likely be used for such a project. (Other technologies such as internal combustion engines may also be used to generate electricity.) The capacity is estimated based on a 40% and on a 60% recovery efficiency (i.e. percentage of total emissions recovered). The formula is:

Generating Capacity (kW): $\text{CH}_4 \text{ liberated in cf/day} \times 1 \text{ day/24 hours} \times 1000 \text{ Btus/cf} \times \text{kwh/11,000 Btus.}$

Summary Table 19 lists the mines according to their potential electric generating capacity in MW.

Pipeline Potential

This section presents data that are useful in determining whether a mine is a good candidate for a pipeline sales project.

Potential Annual Gas Sales: Potential annual gas sales are estimated by multiplying total daily methane emissions by 365 days per year and then multiplying that value by the assumed recovery efficiency. Potential annual gas sales are calculated for both a 40% and a 60% assumed recovery efficiency and are presented in billion cubic feet. The estimated amount of gas that could be produced for sale to a pipeline at each candidate mine is shown in Summary Table 20.

Description of Surrounding Terrain: The terrain surrounding the mine is described as this is an important factor in determining the costs of laying gathering lines for the project. While many mines in Appalachia are located in hilly or mountainous terrain, mines in the Illinois Basin tend to be located on relatively flat plains.

Pipeline in County: A "yes" indicates that an existing commercial pipeline runs through the county.

Owner of Nearest Pipeline: The corporate owner of the pipeline located closest to the mine is provided. If a mine is utilizing methane it is assumed that the owner of the nearest pipeline is the mine itself. The mine's pipeline would connect the mine to a commercial pipeline.

Distance to Pipeline: The estimated distance from the closest pipeline to the mine is provided. Some western coal mines may be more than 20 miles from the nearest pipeline. In contrast, most eastern coal mines are located within ten miles of a commercial pipeline. However, while a mine may be located within close proximity to an existing gas pipeline, there are no guarantees that the pipeline will have enough capacity to take the gas produced from a coal mine. In particular, the Appalachian region tends to have limited pipeline capacity. If a mine is using methane it is assumed that the distance to the nearest commercial pipeline is zero, since the mine would have to have a pipeline in place to transport the gas.

Pipeline Diameter: The diameter (in inches) of the nearest pipeline is provided.

Other Utilization Possibilities

This section addresses the possibility of using methane in a nearby coal-fired power plant or at other nearby industrial or institutional facilities.

Name of Nearby Coal Fired Power Plant: A few of the mines profiled here are located less than ten miles from a coal-fired power plant. For these mines, the name of the nearby power plant is listed. The source of this information, along with the estimated distance to the power plant and the plant capacity, is Energy Systems Associates (1991).

Distance to Plant: The profile shows the estimated distance between the mine and the nearby power plant is shown.

Plant Capacity: The capacity of the nearby power plant is provided.

Nearby Industrial/Institutional Facilities: Some mines are located within a short distance of industrial or institutional facilities that may be able to directly utilize the recovered methane. For these mines, nearby facilities are listed. The sources of this information were local Chambers of Commerce, local phone books, industry directories, and other publicly available resources. Current information on the nearby industrial/institutional facilities information has not yet been obtained for many mines. Accordingly, the words "not yet researched" appear in place of the information.

Summary of Recent News

The final section of the profile is a summary of recent news pertaining to the mine that has been reported in coal industry publications (primarily *Coal*, *Coal Outlook*, and *Coal Week*, though information from other publications is also included). Recent news summaries include information on incidents such as new utility contracts, future plans for the mine, layoffs, strikes, slow-downs, roof collapses, fires, changes in mine management, and the use of new technologies. The recent news summaries help to present an overall picture of the economic health of the mine and the mine's potential as a candidate for the development of a cost-effective methane recovery project.

5. Mine Summary Tables

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Table 1: Mines Listed Alphabetically

MINE NAME	STATE	MINE NAME	STATE
Aberdeen	UT	McClure No. 2	VA
Arch No. 37	KY	McElroy	WV
Arkwright No. 1	WV	Meigs No. 2	OH
Bailey	PA	Meigs No. 31	OH
Baker	KY	Mine 84	PA
Baylor No. 1	WV	Monterey No. 1	IL
Blacksville No. 2	WV	Monterey No. 2	IL
Blue Creek No. 3	AL	Nelms Cadiz Portal	OH
Blue Creek No. 4	AL	North River No. 1	AL
Blue Creek No. 5	AL	Oak Grove	AL
Blue Creek No. 7	AL	Old Ben No. 24	IL
Bowie No. 1	CO	Old Ben No. 25	IL
Brushy Creek	IL	Old Ben No. 26	IL
Buchanan No. 1	VA	Orient No. 6	IL
Buck Creek	IN	Pattiki	IL
Bullitt	VA	Pinnacle	UT
Cambria No. 33	PA	Pinnacle No. 50	WV
Camp No. 11	KY	Pontiki No. 1	KY
Cimarron	NM	Pontiki No. 2	KY
Clean Energy No. 1	KY	Powhatan No. 4	OH
Crown II	IL	Powhatan No. 6	OH
Cumberland	PA	Rend Lake	IL
Deserado	CO	Robinson Run No. 95	WV
Dilworth	PA	Sanborn Creek	CO
Dotiki	KY	Sentinel	WV
Eagle Nest	WV	Shoal Creek	AL
Elkhart	IL	Shoemaker	WV
Emerald No. 1	PA	Soldier Canyon	UT
Enlow Fork	PA	Southfield	CO
Federal No. 2	WV	Tanoma	PA
Freedom Energy No. 1	KY	Urling No. 1	PA
Galatia No. 56	IL	VP No. 3	VA
Golden Eagle	CO	VP No. 8	VA
Grove No. 1	PA	Wabash	IL
Humphrey No. 7	WV	Warwick	PA
Loveridge No. 22	WV	West Elk	CO
Maple Creek	PA	Wheatcroft No. 9	KY
Maple Meadow No. 1	WV	Windsor	WV
Mary Lee No. 1	AL	Wolf Creek No. 4	KY
McClure No. 1	VA		

Table 2: Mines Listed by Operating Status as of 1997

MINE NAME	STATUS	MINE NAME	STATUS
Aberdeen	Operating	Sentinel	Operating
Arch No. 37	Operating	Shoemaker	Operating
Bailey	Operating	Soldier Canyon	Operating
Baker	Operating	Southfield	Operating
Baylor No. 1	Operating	Tanoma	Operating
Bowie No. 1	Operating	Urling No. 1	Operating
Brushy Creek	Operating	Wabash	Operating
Camp No. 11	Operating	West Elk	Operating
Clean Energy No. 1	Operating	Windsor	Operating
Crown II	Operating	Blacksville No. 2	Open/Using
Cumberland	Operating	Blue Creek No. 3	Open/Using
Deserado	Operating	Blue Creek No. 4	Open/Using
Dilworth	Operating	Blue Creek No. 5	Open/Using
Dotiki	Operating	Blue Creek No. 7	Open/Using
Eagle Nest	Operating	Buchanan No. 1	Open/Using
Elkhart	Operating	Federal No. 2	Open/Using
Emerald No. 1	Operating	Oak Grove	Open/Using
Enlow Fork	Operating	Pinnacle No. 50	Open/Using
Freedom Energy No. 1	Operating	Shoal Creek	Open/Using
Galatia No. 56	Operating	VP No. 3	Open/Using
Grove No. 1	Operating	Loveridge No. 22	Open/Using ¹
Maple Creek	Operating	VP No. 8	Open/Using
Maple Meadow No. 1	Operating	Buck Creek	Idle
McClure No. 2	Operating	Bullitt	Idle
McElroy	Operating	Monterey No. 2	Idle
Meigs No. 2	Operating	Warwick	Idle
Meigs No. 31	Operating	Humphrey No. 7	Closing/Using
Mine 84	Operating	Mary Lee No. 1	Closing
Monterey No. 1	Operating	Golden Eagle	Closed/Using
Nelms Cadiz Portal	Operating	Arkwright No. 1	Closed
North River No. 1	Operating	Cambria No. 33	Closed
Orient No. 6	Operating	Cimarron	Closed
Pattiki	Operating	McClure No. 1	Closed
Pontiki No. 1	Operating	Old Ben No. 24	Closed
Pontiki No. 2	Operating	Old Ben No. 25	Closed
Powhatan No. 4	Operating	Old Ben No. 26	Closed
Powhatan No. 6	Operating	Pinnacle	Closed
Rend Lake	Operating	Wheatcroft No. 9	Closed
Robinson Run No. 95	Operating	Wolf Creek No. 4	Closed
Sanborn Creek	Operating		

Table 3: Mines Listed by State/County

MINE NAME	STATE	COUNTY	MINE NAME	STATE	COUNTY
North River No. 1	AL	Fayette	Meigs No. 2	OH	Meigs
Blue Creek No. 3	AL	Jefferson	Meigs No. 31	OH	Meigs
Oak Grove	AL	Jefferson	Powhatan No. 4	OH	Monroe
Shoal Creek	AL	Jefferson	Powhatan No. 6	OH	Monroe
Blue Creek No. 4	AL	Tuscaloosa	Cambria No. 33	PA	Cambria
Blue Creek No. 5	AL	Tuscaloosa	Bailey	PA	Greene
Blue Creek No. 7	AL	Tuscaloosa	Cumberland	PA	Greene
Mary Lee No. 1	AL	Walker	Dilworth	PA	Greene
Bowie No. 1	CO	Delta	Emerald No. 1	PA	Greene
Southfield	CO	Fremont	Enlow Fork	PA	Greene
Sanborn Creek	CO	Gunnison	Warwick	PA	Greene
West Elk	CO	Gunnison	Tanoma	PA	Indiana
Golden Eagle	CO	Las Animas	Urling No. 1	PA	Indiana
Deserado	CO	Rio Blanco	Grove No. 1	PA	Somerset
Monterey No. 2	IL	Clinton	Maple Creek	PA	Washington
Old Ben No. 24	IL	Franklin	Mine 84	PA	Washington
Old Ben No. 25	IL	Franklin	Aberdeen	UT	Carbon
Old Ben No. 26	IL	Franklin	Pinnacle	UT	Carbon
Orient No. 6	IL	Jefferson	Soldier Canyon	UT	Carbon
Rend Lake	IL	Jefferson	Buchanan No. 1	VA	Buchanan
Elkhart	IL	Logan	VP No. 3	VA	Buchanan
Crown II	IL	Macoupin	VP No. 8	VA	Buchanan
Monterey No. 1	IL	Macoupin	McClure No. 1	VA	Dickenson
Brushy Creek	IL	Saline	McClure No. 2	VA	Dickenson
Galatia No. 56	IL	Saline	Bullitt	VA	Wise
Wabash	IL	Wabash	Sentinel	WV	Barbour
Pattiki	IL	White	Eagle Nest	WV	Boone
Buck Creek	IN	Sullivan	Windsor	WV	Brooke
Arch No. 37	KY	Harlan	Robinson Run No. 95	WV	Harrison
Pontiki No. 1	KY	Martin	Loveridge No. 22	WV	Marion
Pontiki No. 2	KY	Martin	McElroy	WV	Marshall
Wolf Creek No. 4	KY	Martin	Shoemaker	WV	Marshall
Clean Energy No. 1	KY	Pike	Arkwright No. 1	WV	Monongalia
Freedom Energy No. 1	KY	Pike	Blacksville No. 2	WV	Monongalia
Camp No. 11	KY	Union	Federal No. 2	WV	Monongalia
Baker	KY	Webster	Humphrey No. 7	WV	Monongalia
Dotiki	KY	Webster	Baylor No. 1	WV	Raleigh
Wheatcroft No. 9	KY	Webster	Maple Meadow No. 1	WV	Raleigh
Cimarron	NM	Colfax	Pinnacle No. 50	WV	Wyoming
Nelms Cadiz Portal	OH	Harrison			

Table 4: Mines Listed by Coal Basin

COAL BASIN/ MINE NAME	ESTIMATED SPECIFIC EMISSIONS (CF/TON)
Central Appalachian	
Arch No. 37	77
Baylor No. 1	462
Buchanan No. 1	NA
Bullitt	0*
Clean Energy No. 1	312
Eagle Nest	159
Freedom Energy No. 1	232
Maple Meadow No. 1	945
McClure No. 1	0*
McClure No. 2	1,006
Pinnacle No. 50	1,922
Pontiki No. 1	177
Pontiki No. 2	408
VP No. 3	NA
VP No. 8	NA
Wolf Creek No. 4	0*
Illinois	
Baker	115
Brushy Creek	506
Buck Creek	0*
Camp No. 11	106
Crown II	148
Dotiki	74
Elkhart	55
Galatia No. 56	498
Monterey No. 1	75
Monterey No. 2	88
Old Ben No. 24	878
Old Ben No. 25	0*
Old Ben No. 26	186
Orient No. 6	230
Pattiki	345
Rend Lake	252
Wabash	530
Wheatcroft No. 9	0*
Northern Appalachian	
Arkwright No. 1	0*
Bailey	399
Blacksville No. 2	1,074
Cambria No. 33	0*
Cumberland	768
Dilworth	314
Emerald No. 1	1,092
Enlow Fork	600

* Mines whose estimated specific emissions are 0 were either closed or idle in 1996.

Table 4: Mines Listed by Coal Basin

COAL BASIN/ MINE NAME	ESTIMATED SPECIFIC EMISSIONS (CF/TON)
Federal No. 2	1,142
Grove No. 1	78
Humphrey No. 7	850
Loveridge No. 22	875
Maple Creek	75
McElroy	288
Meigs No. 2	62
Meigs No. 31	134
Mine 84	495
Nelms Cadiz Portal	230
Powhatan No. 4	183
Powhatan No. 6	31
Robinson Run No. 95	390
Sentinel	490
Shoemaker	207
Tanoma	589
Urling No. 1	380
Warwick	214
Windsor	76
Warrior	
Blue Creek No. 3	4,428
Blue Creek No. 4	3,221
Blue Creek No. 5	5,853
Blue Creek No. 7	4,638
Mary Lee No. 1	462
North River No. 1	532
Oak Grove	2,304
Shoal Creek	901
Western (Canon City Field)	
Southfield	859
Western (Piceance)	
Bowie No. 1	723
Deserado	459
Sanborn Creek	1,419
West Elk	252
Western (Raton Mesa)	
Cimarron	0*
Golden Eagle	0*
Western (Uinta)	
Aberdeen	210
Pinnacle	0*
Soldier Canyon	1,271

Table 5: Mines Listed by Coalbed

MINE NAME	COALBED	MINE NAME	COALBED
Aberdeen	Aberdeen	Mary Lee No. 1	Mary Lee
Arch No. 37	Alma	Shoal Creek	Mary Lee, Blue Creek
Sanborn Creek	B Seam	Golden Eagle	Maxwell
West Elk	B Seam	Eagle Nest	Millard
Bowie No. 1	Basin D	Arkwright No. 1	Pittsburgh
Deserado	Basin D/C	Bailey	Pittsburgh
Baylor No. 1	Beckley	Blacksville No. 2	Pittsburgh
Maple Meadow No. 1	Beckley	Cumberland	Pittsburgh
Blue Creek No. 3	Blue Creek	Dilworth	Pittsburgh
Blue Creek No. 4	Blue Creek	Emerald No. 1	Pittsburgh
Blue Creek No. 5	Blue Creek	Enlow Fork	Pittsburgh
Blue Creek No. 7	Blue Creek	Federal No. 2	Pittsburgh
Oak Grove	Blue Creek	Humphrey No. 7	Pittsburgh
Meigs No. 2	Clarion No. 4A	Loveridge No. 22	Pittsburgh
Meigs No. 31	Clarion No. 4A	Maple Creek	Pittsburgh
Bullitt	Dorchester	McElroy	Pittsburgh
Nelms Cadiz Portal	Freeport (L)	Mine 84	Pittsburgh
Urling No. 1	Freeport (L)	Powhatan No. 4	Pittsburgh
Pinnacle	Gilson & Centennial	Powhatan No. 6	Pittsburgh
Brushy Creek	Herrin No. 6	Robinson Run No. 95	Pittsburgh
Crown II	Herrin No. 6	Shoemaker	Pittsburgh
Monterey No. 1	Herrin No. 6	Windsor	Pittsburgh
Monterey No. 2	Herrin No. 6	Buchanan No. 1	Pocahontas No. 3
Old Ben No. 24	Herrin No. 6	Pinnacle No. 50	Pocahontas No. 3
Old Ben No. 25	Herrin No. 6	VP No. 3	Pocahontas No. 3
Old Ben No. 26	Herrin No. 6	VP No. 8	Pocahontas No. 3
Orient No. 6	Herrin No. 6	Clean Energy No.1	Pond Creek
Pattiki	Herrin No. 6	Freedom Energy No.1	Pond Creek
Rend Lake	Herrin No. 6	Pontiki No. 1	Pond Creek
Galatia No. 56	Herrin No. 6/Harrisburg No. 5	Pontiki No. 2	Pond Creek
Southfield	Jack-o-Lantern & Red Arrow	North River No. 1	Pratt
McClure No. 1	Jawbone	Soldier Canyon	Rock Canyon & Sunnyside
McClure No. 2	Jawbone	Warwick	Sewickley
Baker	Kentucky No. 13	Buck Creek	Springfield No. 5
Wheatcroft No. 9	Kentucky No. 9/Springfield No. 5	Camp No. 11	Springfield No. 5
Sentinel	Kittaning (L)	Dotiki	Springfield No. 5
Tanoma	Kittaning (L)	Elkhart	Springfield No. 5
Cambria No. 33	Kittaning (U&L)	Wabash	Springfield No. 5
Grove No. 1	Kittaning (U)	Wolf Creek No. 4	Warfield/Pond Creek
Cimarron	Left Fork (U)		

Table 6: Mines Listed by Company

PARENT COMPANY/ COAL COMPANY	MINE NAME
A. T. Massey Coal Co., Inc.	
Sidney Coal Company	Clean Energy No. 1
Sidney Coal Company	Freedom Energy No. 1
American Electric Power	
Ohio Power Co., Southern Ohio Coal Co.	Meigs No. 2
Ohio Power Co., Southern Ohio Coal Co.	Meigs No. 31
Windsor Coal Co.	Windsor
American Metals & Coal International, Inc. (AMCI)	
Tanoma Mining Co., Inc.	Tanoma
Andalex Resources, Inc.	
Andalex Resources, Inc.	Aberdeen
Andalex Resources, Inc.	Pinnacle
Anker Energy	
Philippi Development Inc	Sentinel
Arch Mineral Corp. (Ashland Oil/Hunt)	
Arch of Kentucky, Division of Apogee Coal	Arch No. 37
Atlantic Richfield/ITOCU Corp.	
Mountain Coal	West Elk
Soldier Creek Coal Co.	Soldier Canyon
Baylor Mining, Inc.	
Baylor Mining, Inc.	Baylor No. 1
Bethlehem Steel Corp.	
A. T. Massey Coal Co., Inc.	Eagle Nest
BethEnergy Mines Inc.	Cambria No. 33
Bowie Resources	
Bowie Resources	Bowie No. 1

Table 6: Mines Listed by Company

**PARENT COMPANY/
COAL COMPANY****MINE NAME****Chevron**

Pittsburgh & Midway Coal Mining Co.

Cimarron

Pittsburgh & Midway Coal Mining Co.

North River No. 1

CONSOL Coal Group (Du Pont/Rheinbraun AG)

CONSOL Pennsylvania Coal Co.

Bailey

Consolidation Coal Co.

Arkwright No. 1

Consolidation Coal Co.

Blacksville No. 2

Consolidation Coal Co.

Buchanan No. 1

Consolidation Coal Co.

Dilworth

Consolidation Coal Co.

Humphrey No. 7

Consolidation Coal Co.

Loveridge No. 22

Consolidation Coal Co.

Rend Lake

Consolidation Coal Co.

Robinson Run No. 95

Consolidation Coal Co.

Shoemaker

Consolidation Coal, Island Creek Coal

VP No. 3

Consolidation Coal, Island Creek Coal

VP No. 8

Enlow Fork Mining Co.

Enlow Fork

McElroy Coal Co./Consolidation Coal Co.

McElroy

Quarto Mining

Powhatan No. 4

Cyprus Amax

Amax Coal Co.

Wabash

Maple Meadow Mining

Maple Meadow No. 1

PA Services Corp., Cyprus Cumberland Resources

Cumberland

PA Services Corp., Cyprus Emerald Resources

Emerald No. 1

DQE

Duquesne Light/New Warwick Mining Co. (Aloe Mining)

Warwick

Drummond Company, Inc.

Drummond Company, Inc.

Mary Lee No. 1

Drummond Company, Inc.

Shoal Creek

Energy Fuels Coal, Inc.

Energy Fuels Coal, Inc.

Southfield

Table 6: Mines Listed by Company

PARENT COMPANY/ COAL COMPANY	MINE NAME
Entech Coal (a subsidiary of Montana Power)	
Basin Resources	Golden Eagle
Exxon Corp.	
Monterey Coal	Monterey No. 1
Monterey Coal	Monterey No. 2
General Dynamics Corp.	
Freeman United Coal Mining Co.	Crown II
Freeman United Coal Mining Co.	Orient No. 6
Harrison Mining Corp.	
Harrison Mining Corp.	Nelms Cadiz Portal
Kerr-McGee Corp.	
Kerr-McGee Coal Corp.	Galatia No. 56
Lion Mining Co.	
Lion Mining Co.	Grove No. 1
MAPCO Coal, Inc. (Beacon Energy Investment Fund)	
Pontiki Coal Corp.	Pontiki No. 1
Pontiki Coal Corp.	Pontiki No. 2
Webster County Coal Corp.	Dotiki
White County Coal Corp.	Pattiki
Maple Creek Mining Inc.	
Maple Creek Mining Inc.	Maple Creek
Ohio Valley Resources	
Ohio Valley Coal Co.	Powhatan No. 6
Orion Diversified Technologies	
Orion Resource Energie	Buck Creek
Oxbow Carbon and Mineral Group	
Pacific Basin Resources	Sanborn Creek

Table 6: Mines Listed by Company

PARENT COMPANY/ COAL COMPANY	MINE NAME
Peabody Holding Co., Hanson PLC	
Eastern Assoc. Coal	Federal No. 2
Peabody Coal Company	Camp No. 11
Pittston Coal Management Co.	
Clinchfield Coal	McClure No. 1
Clinchfield Coal	McClure No. 2
Rochester and Pittsburgh Coal Co.	
Eighty Four Mining Co.	Mine 84
Keystone Coal Mining	Urling No. 1
The Renco Group	
The Renco Group	Baker
The Renco Group	Wheatcroft No. 9
USX Corp.	
U.S. Steel Mining Co., Inc.	Oak Grove
U.S. Steel Mining Co., Inc.	Pinnacle No. 50
Walter Industries, Inc.	
Jim Walter Resources	Blue Creek No. 3
Jim Walter Resources	Blue Creek No. 4
Jim Walter Resources	Blue Creek No. 5
Jim Walter Resources	Blue Creek No. 7
Western Fuels	
Western Fuels-Illinois/Brushy Creek Coal Co.	Brushy Creek
Western Fuels-Utah	Deserado
Westmoreland Resources, Inc.	
Westmoreland Coal Co.	Bullitt
Zeigler Coal Holding Company	
Old Ben Coal Co.	Old Ben No. 24
Old Ben Coal Co.	Old Ben No. 25
Old Ben Coal Co.	Old Ben No. 26
Turris Coal Co.	Elkhart
Wolf Creek Collieries	Wolf Creek No. 4

Table 7: Mines Listed by Mining Method

MINE NAME	METHOD	MINE NAME	METHOD
Arkwright No. 1	Longwall	Powhatan No. 6	Longwall
Bailey	Longwall	Rend Lake	Longwall
Baker	Longwall	Robinson Run No. 95	Longwall
Blacksville No. 2	Longwall	Shoal Creek	Longwall
Blue Creek No. 3	Longwall	Shoemaker	Longwall
Blue Creek No. 4	Longwall	VP No. 3	Longwall
Blue Creek No. 5	Longwall	VP No. 8	Longwall
Blue Creek No. 7	Longwall	Warwick	Longwall
Buchanan No. 1	Longwall	West Elk	Longwall
Bullitt	Longwall	Wheatcroft No. 9	Longwall
Cambria No. 33	Longwall	Windsor	Longwall
Camp No. 11	Longwall	Aberdeen	Room & Pillar
Cimarron	Longwall	Arch No. 37	Room & Pillar
Cumberland	Longwall	Baylor No. 1	Room & Pillar
Deserado	Longwall	Bowie No. 1	Room & Pillar
Dilworth	Longwall	Brushy Creek	Room & Pillar
Eagle Nest	Longwall	Buck Creek	Room & Pillar
Emerald No. 1	Longwall	Clean Energy No. 1	Room & Pillar
Enlow Fork	Longwall	Crown II	Room & Pillar
Federal No. 2	Longwall	Dotiki	Room & Pillar
Galatia No. 56	Longwall	Elkhart	Room & Pillar
Golden Eagle	Longwall	Freedom Energy No. 1	Room & Pillar
Humphrey No. 7	Longwall	Grove No. 1	Room & Pillar
Loveridge No. 22	Longwall	Maple Meadow No. 1	Room & Pillar
Maple Creek	Longwall	McClure No. 2	Room & Pillar
Mary Lee No. 1	Longwall	Monterey No. 2	Room & Pillar
McClure No. 1	Longwall	Nelms Cadiz Portal	Room & Pillar
McElroy	Longwall	Pattiki	Room & Pillar
Meigs No. 2	Longwall	Pinnacle	Room & Pillar
Meigs No. 31	Longwall	Pontiki No. 1	Room & Pillar
Mine 84	Longwall	Pontiki No. 2	Room & Pillar
Monterey No. 1	Longwall	Sanborn Creek	Room & Pillar
North River No. 1	Longwall	Sentinel	Room & Pillar
Oak Grove	Longwall	Soldier Canyon	Room & Pillar
Old Ben No. 24	Longwall	Southfield	Room & Pillar
Old Ben No. 25	Longwall	Tanoma	Room & Pillar
Old Ben No. 26	Longwall	Urling No. 1	Room & Pillar
Orient No. 6	Longwall	Wabash	Room & Pillar
Pinnacle No. 50	Longwall	Wolf Creek No. 4	Room & Pillar
Powhatan No. 4	Longwall		

Table 8: Mines Listed by Primary Coal Use

MINE NAME	USE	MINE NAME	USE
Arch No. 37	Steam/Metallurgical	Enlow Fork	Steam
Blue Creek No. 3	Steam/Metallurgical	Federal No. 2	Steam
Blue Creek No. 5	Steam/Metallurgical	Humphrey No. 7	Steam
Blue Creek No. 7	Steam/Metallurgical	Loveridge No. 22	Steam
Bowie No. 1	Steam/Metallurgical	McElroy	Steam
Buck Creek	Steam/Metallurgical	Meigs No. 2	Steam
Cambria No. 33	Steam/Metallurgical	Meigs No. 31	Steam
Cimarron	Steam/Metallurgical	Monterey No. 1	Steam
Dilworth	Steam/Metallurgical	Monterey No. 2	Steam
Freedom Energy No. 1	Steam/Metallurgical	Nelms Cadiz Portal	Steam
Galatia No. 56	Steam/Metallurgical	North River No. 1	Steam
Golden Eagle	Steam/Metallurgical	Old Ben No. 24	Steam
Grove No. 1	Steam/Metallurgical	Old Ben No. 25	Steam
Maple Creek	Steam/Metallurgical	Old Ben No. 26	Steam
Mary Lee No. 1	Steam/Metallurgical	Pattiki	Steam
McClure No. 1	Steam/Metallurgical	Pinnacle	Steam
McClure No. 2	Steam/Metallurgical	Pontiki No. 1	Steam
Mine 84	Steam/Metallurgical	Pontiki No. 2	Steam
Orient No. 6	Steam/Metallurgical	Powhatan No. 4	Steam
Rend Lake	Steam/Metallurgical	Powhatan No. 6	Steam
Sanborn Creek	Steam/Metallurgical	Robinson Run No. 95	Steam
Sentinel	Steam/Metallurgical	Shoal Creek	Steam
Tanoma	Steam/Metallurgical	Shoemaker	Steam
Aberdeen	Steam	Soldier Canyon	Steam
Arkwright No. 1	Steam	Southfield	Steam
Bailey	Steam	Urling No. 1	Steam
Baker	Steam	Wabash	Steam
Baylor No. 1	Steam	Warwick	Steam
Blacksville No. 2	Steam	West Elk	Steam
Brushy Creek	Steam	Wheatcroft No. 9	Steam
Buchanan No. 1	Steam	Windsor	Steam
Bullitt	Steam	Wolf Creek No. 4	Steam
Camp No. 11	Steam	Blue Creek No. 4	Metallurgical
Clean Energy No. 1	Steam	Eagle Nest	Metallurgical
Crown II	Steam	Maple Meadow No. 1	Metallurgical
Cumberland	Steam	Oak Grove	Metallurgical
Deserado	Steam	Pinnacle No. 50	Metallurgical
Dotiki	Steam	VP No. 3	Metallurgical
Elkhart	Steam	VP No. 8	Metallurgical
Emerald No. 1	Steam		

Table 9: Mines Listed by Sulfur Content

MINE NAME	SULFUR	MINE NAME	SULFUR
Bowie No. 1	0.39% - 0.50%	Bullitt	1.30%
Soldier Canyon	0.40% - 0.50%	Mine 84	1.33% - 1.76%
Golden Eagle	0.41% - 0.46%	Wabash	1.35% - 1.62%
Deserado	0.43% - 0.53%	Warwick	1.48% - 2.29%
West Elk	0.46%	Dilworth	1.50%
Sanborn Creek	0.47% - 0.62%	Grove No. 1	1.50%
Buck Creek	0.47% - 0.66%	Cumberland	1.59% - 2.62%
Oak Grove	0.53%	Orient No. 6	1.65%
Blue Creek No. 3	0.55% - 0.86%	Wheatcroft No. 9	1.66% - 5.18%
Cimarron	0.56%	Freedom Energy No. 1	1.67%
Blue Creek No. 7	0.58% - 0.70%	North River No. 1	1.75% - 1.91%
Pontiki No. 2	0.60% - 0.73%	Baker	1.76% - 2.95%
Mary Lee No. 1	0.60% - 0.90%	Blacksville No. 2	1.86% - 2.43%
Pontiki No. 1	0.60% - 0.90%	Old Ben No. 25	2.00% - 2.70%
Southfield	0.62% - 0.74%	Humphrey No. 7	2.10% - 2.25%
Shoal Creek	0.63% - 1.10%	Arkwright No. 1	2.15% - 2.63%
Wolf Creek No. 4	0.64% - 2.56%	Federal No. 2	2.17% - 2.79%
Arch No. 37	0.66% - 1.87%	Old Ben No. 26	2.20%
Urling No. 1	0.70% - 1.58%	Old Ben No. 24	2.20% - 2.59%
McClure No. 1	0.70% - 1.82%	Pattiki	2.50% - 2.87%
Galatia No. 56	0.70% - 2.80%	Loveridge No. 22	2.54% - 2.82%
Cambria No. 33	0.71% - 2.05%	Brushy Creek	2.70% - 2.80%
Baylor No. 1	0.72%	Windsor	2.73% - 3.69%
Buchanan No. 1	0.72% - 0.82%	Camp No. 11	2.81%
Blue Creek No. 5	0.72% - 0.88%	Nelms Cadiz Portal	2.81% - 3.50%
Blue Creek No. 4	0.75%	Dotiki	2.87%
Pinnacle No. 50	0.75%	Robinson Run No. 95	2.95% - 3.14%
VP No. 3	0.80%	Elkhart	3.00% - 3.20%
VP No. 8	0.80% - 0.90%	Monterey No. 2	3.30% - 3.54%
Maple Meadow No. 1	0.80% - 1.25%	Crown II	3.40%
Rend Lake	0.81% - 1.81%	Meigs No. 2	3.40%
Emerald No. 1	0.83% - 3.65%	Meigs No. 31	3.40%
Tanoma	0.85%	Powhatan No. 4	3.51% - 4.53%
Eagle Nest	0.85% - 0.91%	Powhatan No. 6	3.85% - 4.80%
Sentinel	0.96% - 1.34%	McElroy	3.98% - 4.42%
McClure No. 2	1.00%	Shoemaker	4.00% - 4.22%
Enlow Fork	1.00% - 2.41%	Aberdeen	NA
Monterey No. 1	1.00% - 3.60%	Clean Energy No. 1	NA
Bailey	1.03% - 2.41%	Pinnacle	NA
Maple Creek	1.16% - 2.10%		

Table 10: Mines Listed by 1996 Coal Production

MINE NAME	MM TONS	MINE NAME	MM TONS
Enlow Fork	8.7	Pattiki	1.8
Bailey	7.5	Sentinel	1.8
Galatia No. 56	6.5	Crown II	1.7
West Elk	5.9	Monterey No. 2	1.7
Baker	5.9	VP No. 3	1.6
Cumberland	5.2	Maple Meadow No. 1	1.5
Dilworth	4.8	Windsor	1.4
Powhatan No. 6	4.7	Eagle Nest	1.4
Federal No. 2	4.6	Clean Energy No. 1	1.3
Arch No. 37	4.5	Mary Lee No. 1	1.2
Shoemaker	4.4	Sanborn Creek	1.2
McElroy	4.3	Pontiki No. 1	1.2
Robinson Run No. 95	4.2	Nelms Cadiz Portal	1.1
Pinnacle No. 50	4.1	Orient No. 6	1.1
Buchanan No. 1	3.6	Freedom Energy No. 1	1.1
Maple Creek	3.4	Soldier Canyon	1.0
Blacksville No. 2	3.4	Baylor No. 1	0.9
Powhatan No. 4	3.4	Urling No. 1	0.9
Shoal Creek	3.4	Pontiki No. 2	0.8
Dotiki	3.3	Blue Creek No. 5	0.6
Humphrey No. 7	3.3	Bowie No. 1	0.6
Wabash	3.2	Brushy Creek	0.6
Emerald No. 1	3.2	Tanoma	0.6
Rend Lake	3.2	Deserado	0.5
Old Ben No. 26	3.1	Old Ben No. 24	0.5
Camp No. 11	3.1	Grove No. 1	0.5
Loveridge No. 22	3.1	McClure No. 2	0.4
Mine 84	3.0	Southfield	0.2
Meigs No. 31	3.0	Arkwright No. 1	0.0
Oak Grove	3.0	Buck Creek	0.0
Meigs No. 2	2.9	Bullitt	0.0
VP No. 8	2.8	Cambria No. 33	0.0
Aberdeen	2.4	Cimarron	0.0
Monterey No. 1	2.4	Golden Eagle	0.0
Blue Creek No. 7	2.4	McClure No. 1	0.0
Blue Creek No. 4	2.4	Old Ben No. 25	0.0
North River No. 1	2.1	Pinnacle	0.0
Elkhart	2.0	Wheatcroft No. 9	0.0
Blue Creek No. 3	2.0	Wolf Creek No. 4	0.0
Warwick	1.9		

Table 11: Mines Listed by 1995 Coal Production

MINE NAME	MM TONS	MINE NAME	MM TONS
Enlow Fork	8.0	Eagle Nest	1.7
Bailey	7.3	Crown II	1.6
Galatia No. 56	5.5	Blue Creek No. 5	1.5
West Elk	5.3	Orient No. 6	1.4
Pinnacle No. 50	5.1	Arkwright No. 1	1.4
Baker	4.3	Pinnacle	1.4
Federal No. 2	4.3	Sentinel	1.4
McElroy	4.1	Mine 84	1.3
Powhatan No. 6	3.9	Warwick	1.3
Arch No. 37	3.9	Mary Lee No. 1	1.2
Shoemaker	3.8	Golden Eagle	1.2
Blacksville No. 2	3.8	Freedom Energy No. 1	1.1
Cumberland	3.8	Maple Meadow No. 1	1.1
Emerald No. 1	3.8	Wolf Creek No. 4	1.1
Robinson Run No. 95	3.7	Wheatcroft No. 9	1.1
Rend Lake	3.3	Sanborn Creek	1.1
Buchanan No. 1	3.2	Pontiki No. 1	1.1
Humphrey No. 7	3.1	Windsor	1.1
Monterey No. 2	3.0	Deserado	1.0
Dilworth	3.0	Clean Energy No. 1	1.0
Old Ben No. 26	3.0	Nelms Cadiz Portal	1.0
Powhatan No. 4	2.7	Maple Creek	0.9
Loveridge No. 22	2.7	Pontiki No. 2	0.8
Wabash	2.6	Urling No. 1	0.7
Camp No. 11	2.5	Baylor No. 1	0.6
Blue Creek No. 4	2.5	Cimarron	0.6
Dotiki	2.5	Grove No. 1	0.6
Oak Grove	2.5	Aberdeen	0.5
Meigs No. 2	2.4	Tanoma	0.5
Old Ben No. 24	2.3	Brushy Creek	0.5
Blue Creek No. 7	2.3	Soldier Canyon	0.5
Meigs No. 31	2.3	Bowie No. 1	0.4
VP No. 8	2.3	McClure No. 2	0.3
Shoal Creek	2.3	Bullitt	0.3
Monterey No. 1	2.1	Southfield	0.3
North River No. 1	2.0	Buck Creek	0.3
Blue Creek No. 3	1.8	McClure No. 1	0.1
VP No. 3	1.8	Cambria No. 33	0.0
Pattiki	1.8	Old Ben No. 25	0.0
Elkhart	1.7		

Table 12: Mines Employing Drainage Systems

MINE NAME	TYPE OF DRAINAGE SYSTEM	ESTIMATED CURRENT DRAINAGE EFFICIENCY¹
Arkwright No. 1	² Vertical Gob, Horizontal Pre-Mine	Mine closed
Bailey	Vertical Gob	40%
Blacksville No. 2	Vertical Gob, Horizontal Pre-Mine	40%
Blue Creek No. 3	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	46%
Blue Creek No. 4	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	46%
Blue Creek No. 5	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	46%
Blue Creek No. 7	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	46%
Buchanan No. 1	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	NA
Cambria No. 33	² Vertical Gob, Horizontal Pre-Mine	Mine closed
Cumberland	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	15%
Deserado	Vertical Gob	40%
Dilworth	Vertical Gob	40%
Emerald No. 1	Vertical Gob, Horizontal Pre-Mine	40%
Enlow Fork	Vertical Gob	40%
Federal No. 2	Vertical Gob, Horizontal Pre-Mine	40%
Golden Eagle	Re-entry of vertical gob and pre-mine wells	Mine closed
Humphrey No. 7	Vertical Gob, Horizontal Pre-Mine	40%
Loveridge No. 22	Vertical Gob, Horizontal Pre-Mine	40%
Oak Grove	Vertical Pre-Mine, Vertical Gob	43%
Pinnacle No. 50	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	50%
Robinson Run No. 95	Vertical Gob, Horizontal Pre-Mine	40%
Shoal Creek	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	40%
VP No. 3	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	NA
VP No. 8	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	NA
Wheatcroft No. 9	² Vertical Gob	Mine closed

1 The assumed current recovery efficiency is estimated based on actual information where available. For most mines, however, these data are not readily available. In such cases a default value of 40% was used. In order to estimate the total amount of methane liberated by Virginia mines using methane in 1996 (Table 1-1), EPA assumed an average recovery efficiency of 53% for the Buchanan No. 1, VP No. 3, and VP No. 8 mines. However, for reasons explained in Chapters 3 and 6, this assumed recovery efficiency may be too low and is therefore listed as "NA" in the profiles.

2 Mine closed; drainage system not active.

Table 13: Mines Listed by Estimated Total Daily Methane Liberated in 1996

MINE NAME MMCF/D	MMCF/D	MINE NAME	
Blue Creek No. 7	30.7	Clean Energy No. 1	1.1
Blue Creek No. 3	24.0	Meigs No. 31	1.1
Oak Grove	21.5	Warwick	1.1
Pinnacle No. 50	21.4	McClure No. 2	1.0
Blue Creek No. 4	21.3	Arch No. 37	1.0
Enlow Fork	14.3	Camp No. 11	0.9
Federal No. 2	14.3	Pontiki No. 2	0.9
Cumberland	10.9	Tanoma	0.9
Blacksville No. 2	10.0	Urling No. 1	0.9
Blue Creek No. 5	9.9	Brushy Creek	0.8
Emerald No. 1	9.7	Crown II	0.7
Galatia No. 56	8.9	Freedom Energy No. 1	0.7
Shoal Creek	8.3	Maple Creek	0.7
Bailey	8.2	Nelms Cadiz Portal	0.7
Humphrey No. 7	7.7	Orient No. 6	0.7
Loveridge No. 22	7.3	Dotiki	0.7
Wabash	4.7	Deserado	0.7
Robinson Run No. 95	4.5	Eagle Nest	0.6
Sanborn Creek	4.5	Pontiki No. 1	0.6
Dilworth	4.2	Bullitt	0.5
Mine 84	4.1	Meigs No. 2	0.5
West Elk	4.1	Monterey No. 1	0.5
Maple Meadow No. 1	3.9	Monterey No. 2	0.4
McElroy	3.4	Powhatan No. 6	0.4
Soldier Canyon	3.4	Southfield	0.4
North River No. 1	3.0	Wolf Creek No. 4	0.4
Shoemaker	2.5	Buck Creek	0.3
Sentinel	2.4	Elkhart	0.3
Rend Lake	2.2	Windsor	0.3
Baker	1.9	Pinnacle	0.2
Pattiki	1.7	Grove No. 1	0.1
Powhatan No. 4	1.7	Wheatcroft No. 9	0.1
Old Ben No. 26	1.6	Arkwright No. 1	0.0
Mary Lee No. 1	1.5	Cambria No. 33	0.0
Aberdeen	1.4	Cimarron	0.0
McClure No. 1	1.4	Golden Eagle	0.0
Baylor No. 1	1.2	Old Ben No. 25	0.0
Bowie No. 1	1.2	Buchanan No. 1	NA
Old Ben No. 24	1.2	VP No. 3	NA

Table 14: Mines Listed by Daily Ventilation Emissions in 1996

MINE NAME	MMCF/D	MINE NAME	MMCF/D
Blue Creek No. 7	16.6	Bowie No. 1	1.2
VP No. 8	13.2	Old Ben No. 24	1.2
Blue Creek No. 3	13.0	Clean Energy No. 1	1.1
Buchanan No. 1	12.8	Meigs No. 31	1.1
Oak Grove	12.3	Warwick	1.1
Blue Creek No. 4	11.5	McClure No. 2	1.0
Pinnacle No. 50	10.7	Arch No. 37	1.0
Cumberland	9.3	Camp No. 11	0.9
Galatia No. 56	8.9	Pontiki No. 2	0.9
Enlow Fork	8.6	Tanoma	0.9
Federal No. 2	8.6	Urling No. 1	0.9
VP No. 3	6.9	Brushy Creek	0.8
Blacksville No. 2	6.0	Crown II	0.7
Emerald No. 1	5.8	Freedom Energy No. 1	0.7
Blue Creek No. 5	5.4	Maple Creek	0.7
Shoal Creek	5.0	Nelms Cadiz Portal	0.7
Bailey	4.9	Orient No. 6	0.7
Wabash	4.7	Dotiki	0.7
Humphrey No. 7	4.6	Eagle Nest	0.6
Sanborn Creek	4.5	Pontiki No. 1	0.6
Loveridge No. 22	4.4	Bullitt	0.5
Mine 84	4.1	Meigs No. 2	0.5
West Elk	4.1	Monterey No. 1	0.5
Maple Meadow No. 1	3.9	Monterey No. 2	0.4
McElroy	3.4	Deserado	0.4
Soldier Canyon	3.4	Powhatan No. 6	0.4
North River No. 1	3.0	Southfield	0.4
Robinson Run No. 95	2.7	Wolf Creek No. 4	0.4
Dilworth	2.5	Buck Creek	0.3
Shoemaker	2.5	Elkhart	0.3
Sentinel	2.4	Windsor	0.3
Rend Lake	2.2	Pinnacle	0.2
Baker	1.9	Grove No. 1	0.1
Pattiki	1.7	Wheatcroft No. 9	0.1
Powhatan No. 4	1.7	Arkwright No. 1	0.0
Old Ben No. 26	1.6	Cambria No. 33	0.0
Mary Lee No. 1	1.5	Cimarron	0.0
Aberdeen	1.4	Golden Eagle	0.0
McClure No. 1	1.4	Old Ben No. 25	0.0
Baylor No. 1	1.2		

Table 15: Mines Listed by Estimated Daily Methane Drained in 1996

MINE NAME	MMCF/D	MINE NAME	MMCF/D
Blue Creek No. 7	14.1	Maple Meadow No. 1	0.0
Blue Creek No. 3	11.0	Mary Lee No. 1	0.0
Pinnacle No. 50	10.7	McClure No. 1	0.0
Blue Creek No. 4	9.8	McClure No. 2	0.0
Oak Grove	9.3	McElroy	0.0
Enlow Fork	5.7	Meigs No. 2	0.0
Federal No. 2	5.7	Meigs No. 31	0.0
Blue Creek No. 5	4.6	Mine 84	0.0
Blacksville No. 2	4.0	Monterey No. 1	0.0
Emerald No. 1	3.9	Monterey No. 2	0.0
Shoal Creek	3.3	Nelms Cadiz Portal	0.0
Bailey	3.3	North River No. 1	0.0
Humphrey No. 7	3.1	Old Ben No. 24	0.0
Loveridge No. 22	2.9	Old Ben No. 25	0.0
Robinson Run No. 95	1.8	Old Ben No. 26	0.0
Dilworth	1.7	Orient No. 6	0.0
Cumberland	1.6	Pattiki	0.0
Deserado	0.3	Pinnacle	0.0
Aberdeen	0.0	Pontiki No. 1	0.0
Arch No. 37	0.0	Pontiki No. 2	0.0
Arkwright No. 1	0.0	Powhatan No. 4	0.0
Baker	0.0	Powhatan No. 6	0.0
Baylor No. 1	0.0	Rend Lake	0.0
Bowie No. 1	0.0	Sanborn Creek	0.0
Brushy Creek	0.0	Sentinel	0.0
Buck Creek	0.0	Shoemaker	0.0
Bullitt	0.0	Soldier Canyon	0.0
Cambria No. 33	0.0	Southfield	0.0
Camp No. 11	0.0	Tanoma	0.0
Cimarron	0.0	Urling	0.0
Clean Energy No. 1	0.0	Wabash	0.0
Crown II	0.0	Warwick	0.0
Dotiki	0.0	West Elk	0.0
Eagle Nest	0.0	Wheatcroft No. 9	0.0
Elkhart	0.0	Windsor	0.0
Freedom Energy No. 1	0.0	Wolf Creek No. 4	0.0
Galatia No. 56	0.0	Buchanan No. 1	NA
Golden Eagle	0.0	VP No. 3	NA
Grove No. 1	0.0	VP No. 8	NA
Maple Creek	0.0		

Table 16: Mines Listed by Estimated Specific Emissions in 1996

MINE NAME	CF/TON	MINE NAME	CF/TON
Blue Creek No. 5	5,853	West Elk	252
Blue Creek No. 7	4,638	Freedom Energy No. 1	232
Blue Creek No. 3	4,428	Nelms Cadiz Portal	230
Blue Creek No. 4	3,221	Orient No. 6	230
Oak Grove	2,627	Warwick	214
Pinnacle No. 50	1,922	Aberdeen	210
Sanborn Creek	1,419	Shoemaker	207
Soldier Canyon	1,271	Old Ben No. 26	186
Federal No. 2	1,142	Powhatan No. 4	183
Emerald No. 1	1,092	Pontiki No. 1	177
Blacksville No. 2	1,074	Eagle Nest	159
McClure No. 2	1,006	Crown II	148
Maple Meadow No. 1	945	Meigs No. 31	134
Shoal Creek	901	Baker	115
Old Ben No. 24	878	Camp No. 11	106
Loveridge No. 22	875	Monterey No. 2	88
Southfield	859	Grove No. 1	78
Humphrey No. 7	850	Arch No. 37	77
Cumberland	768	Windsor	76
Bowie No. 1	723	Maple Creek	75
Enlow Fork	600	Monterey No. 1	75
Tanoma	589	Dotiki	74
North River No. 1	532	Meigs No. 2	62
Wabash	530	Elkhart	55
Brushy Creek	506	Powhatan No. 6	31
Galatia No. 56	498	Arkwright No. 1	0
Mine 84	495	Buck Creek	0
Sentinel	490	Bullitt	0
Baylor No. 1	462	Cambria No. 33	0
Mary Lee No. 1	462	Cimarron	0
Deserado	459	Golden Eagle	0
Pontiki No. 2	408	McClure No. 1	0
Bailey	399	Old Ben No. 25	0
Robinson Run No. 95	390	Pinnacle	0
Urling No. 1	380	Wheatcroft No. 9	0
Pattiki	345	Wolf Creek No. 4	0
Dilworth	314	Buchanan No. 1	NA
Clean Energy No. 1	312	VP No. 3	NA
McElroy	288	VP No. 8	NA
Rend Lake	252		

**Table 17: Mines Listed by CO₂ Equivalent of
Potential Annual CH₄ Emissions Reductions¹**

MINE NAME CO₂/YR²	MM TONS CO₂/YR²	MINE NAME	MM TONS
Blue Creek No. 7	1.99 - 2.99	Baker	0.12 - 0.18
Buchanan No. 1	1.96 - 2.94	Pattiki	0.11 - 0.17
VP No. 8	1.62 - 2.43	Powhatan No. 4	0.11 - 0.17
Blue Creek No. 3	1.56 - 2.33	Old Ben No. 26	0.10 - 0.16
Pinnacle No. 50	1.39 - 2.08	Mary Lee No. 1	0.10 - 0.15
Blue Creek No. 4	1.38 - 2.07	Aberdeen	0.09 - 0.14
Oak Grove	1.40 - 2.10	Baylor No. 1	0.08 - 0.12
Enlow Fork	0.93 - 1.40	Bowie No. 1	0.08 - 0.12
Federal No. 2	0.93 - 1.40	Old Ben No. 24	0.08 - 0.12
VP No. 3	0.90 - 1.36	Clean Energy No. 1	0.07 - 0.11
Cumberland	0.71 - 1.06	Meigs No. 31	0.07 - 0.11
Blacksville No. 2	0.65 - 0.97	Warwick	0.07 - 0.11
Blue Creek No. 5	0.64 - 0.97	McClure No. 2	0.06 - 0.10
Emerald No. 1	0.63 - 0.94	Old Ben No. 25	0.06 - 0.10
Cambria No. 33	0.62 - 0.92	Arch No. 37	0.06 - 0.09
Galatia No. 56	0.58 - 0.87	Camp No. 11	0.06 - 0.09
Shoal Creek	0.54 - 0.81	Pontiki No. 2	0.06 - 0.09
Bailey	0.53 - 0.79	Tanoma	0.06 - 0.09
Humphrey No. 7	0.50 - 0.75	Urling No. 1	0.06 - 0.09
Golden Eagle	0.49 - 0.73	Wolf Creek No. 4	0.06 - 0.08
Loveridge No. 22	0.48 - 0.71	Brushy Creek	0.05 - 0.08
Wabash	0.30 - 0.46	Crown II	0.05 - 0.07
Robinson Run No. 95	0.29 - 0.44	Freedom Energy No. 1	0.05 - 0.07
Sanborn Creek	0.29 - 0.44	Maple Creek	0.05 - 0.07
Dilworth	0.27 - 0.41	Nelms Cadiz Portal	0.05 - 0.07
Mine 84	0.27 - 0.40	Orient No. 6	0.05 - 0.07
West Elk	0.27 - 0.40	Pinnacle	0.05 - 0.07
Maple Meadow No. 1	0.25 - 0.38	Dotiki	0.04 - 0.07
McElroy	0.22 - 0.33	Deserado	0.04 - 0.06
Soldier Canyon	0.22 - 0.33	Eagle Nest	0.04 - 0.06
Wheatcroft No. 9	0.22 - 0.32	Pontiki No. 1	0.04 - 0.05
North River No. 1	0.19 - 0.29	Bullitt	0.03 - 0.05
Arkwright No. 1	0.17 - 0.26	Meigs No. 2	0.03 - 0.05
Shoemaker	0.16 - 0.24	Monterey No. 1	0.03 - 0.05
McClure No. 1	0.16 - 0.23	Monterey No. 2	0.03 - 0.04
Sentinel	0.16 - 0.23	Buck Creek	0.03 - 0.04
Rend Lake	0.14 - 0.21	Powhatan No. 6	0.03 - 0.04

¹ Based on latest year for which data are available.

² Range is calculated assuming that 40% to 60% of total liberated methane could be recovered. For this table, this range is used for of the mines regardless of the assumed current drainage efficiency (which is 0% for those mines that do not already have a drainage system in place).

Table 17: Mines Listed by CO₂ Equivalent of Potential Annual CH₄ Emissions Reductions¹

MINE NAME CO₂/YR²	MM TONS CO₂/YR²	MINE NAME	MM TONS
Southfield	0.03 - 0.04		
Cimarron	0.02 - 0.03		
Elkhart	0.02 - 0.03		
Windsor	0.02 - 0.03		
Grove No. 1	0.01 - 0.01		

¹ Based on latest year for which data are available.

² Range is calculated assuming that 40% to 60% of total liberated methane could be recovered. For this table, this range is used for of the mines regardless of the assumed current drainage efficiency (which is 0% for those mines that do not already have a drainage system in place).

Table 18: Mines Listed by Electric Utility Supplier

UTILITY PARENT COMPANY/ MINE NAME	UTILITY COMPANY
Allegheny Power Systems, Inc.	
Arkwright No. 1	Monongahela Power Co.
Blacksville No. 2	Monongahela Power Co.
Federal No. 2	Monongahela Power Co.
Humphrey No. 7	Monongahela Power Co.
Loveridge No. 22	Monongahela Power Co.
Robinson Run No. 95	Monongahela Power Co.
Bailey	West Penn Power Co.
Cumberland	West Penn Power Co.
Dilworth	West Penn Power Co.
Emerald No. 1	West Penn Power Co.
Enlow Fork	West Penn Power Co.
Maple Creek	West Penn Power Co.
Mine 84	West Penn Power Co.
American Electric Power Co., Inc.	
Baylor No. 1	Appalachian Power Co.
Buchanan No. 1	Appalachian Power Co.
Eagle Nest	Appalachian Power Co.
Maple Meadow No. 1	Appalachian Power Co.
McClure No. 1	Appalachian Power Co.
McClure No. 2	Appalachian Power Co.
Pinnacle No. 50	Appalachian Power Co.
VP No. 3	Appalachian Power Co.
VP No. 8	Appalachian Power Co.
Windsor	Appalachian Power Co.
Meigs No. 2	Columbus Southern Power Co.
Meigs No. 31	Columbus Southern Power Co.
Pontiki No. 1	Kentucky Power Co.
Pontiki No. 2	Kentucky Power Co.
Wolf Creek No. 4	Kentucky Power Co.
McElroy	Wheeling Power Co.
Shoemaker	Wheeling Power Co.
Cilcorp, Inc.	
Elkhart	Central Illinois Light Company
Cincinnati Gas and Electric Co.	
Nelms Cadiz Portal	Cincinnati Gas and Electric Co.
CIPSCO, Inc.	
Brushy Creek	Central Illinois Public Service
Crown II	Central Illinois Public Service

Table 18: Mines Listed by Electric Utility Supplier

UTILITY PARENT COMPANY/ MINE NAME	UTILITY COMPANY
Galatia No. 56	Central Illinois Public Service
Old Ben No. 24	Central Illinois Public Service
Old Ben No. 25	Central Illinois Public Service
Old Ben No. 26	Central Illinois Public Service
Orient No. 6	Central Illinois Public Service
Rend Lake	Central Illinois Public Service
Deseret Generation & Transmission Cooperative	
Deserado	Moon Lake Electric
DPL Inc.	
Powhatan No. 6	The Dayton Power & Light Co.
DQE	
Tanoma	Duquesne Light Co.
Urling No. 1	Duquesne Light Co.
Warwick	Duquesne Light Co.
General Public Utilities Corp.	
Cambria No. 33	Pennsylvania Electric Co.
Grove No. 1	Pennsylvania Electric Co.
KU Energy	
Arch No. 37	Kentucky Utilities Co.
Baker	Kentucky Utilities Co.
Bullitt	Kentucky Utilities Co.
Camp No. 11	Kentucky Utilities Co.
Clean Energy No. 1	Kentucky Utilities Co.
Dotiki	Kentucky Utilities Co.
Freedom Energy No. 1	Kentucky Utilities Co.
Wheatcroft No. 9	Kentucky Utilities Co.
None	
Powhatan No. 4	Belmont Electric Cooperative
Pattiki	Carmi Water & Light Dept.
West Elk	Delta-Montrose Elec. Assoc./Gunnison County Elec. Assoc.
Bowie No. 1	Delta-Montrose Elec. Assoc./Empire Elec. Assoc.
Sanborn Creek	Gunnison Light & Water Dept.
Monterey No. 1	Illinois Power Co.
Monterey No. 2	Illinois Power Co.
Sentinel	Philippi Municipal Electric
Cimarron	Raton Public Service Co.
Golden Eagle	San Isabel Electric Services, Inc.
Wabash	Wayne White Counties Elec. Coop./Norris Elec. Coop.

Table 18: Mines Listed by Electric Utility Supplier

UTILITY PARENT COMPANY/ MINE NAME	UTILITY COMPANY
Southfield	Westplains Energy
PacifiCorp	
Aberdeen	Price City Utilities, Utah Power & Light
Pinnacle	Price City Utilities, Utah Power & Light
Soldier Canyon	Price City Utilities, Utah Power & Light
PSI Resources Inc.	
Buck Creek	PSI Energy, Inc.
The Southern Co.	
Blue Creek No. 3	Alabama Power Co.
Blue Creek No. 4	Alabama Power Co.
Blue Creek No. 5	Alabama Power Co.
Blue Creek No. 7	Alabama Power Co.
Mary Lee No. 1	Alabama Power Co.
North River No. 1	Alabama Power Co.
Oak Grove	Alabama Power Co.
Shoal Creek	Alabama Power Co.

Table 19: Mines Listed by Potential Electric Generating Capacity¹

MINE NAME	MEGAWATTS ²	MINE NAME	MEGAWATTS ²
Blue Creek No. 7	46.6 - 69.9	Powhatan No. 4	2.6 - 3.9
Buchanan No. 1	45.8 - 68.8	Old Ben No. 26	2.4 - 3.6
VP No. 8	37.9 - 56.8	Mary Lee No. 1	2.3 - 3.4
Blue Creek No. 3	36.3 - 54.5	Aberdeen	2.1 - 3.2
Oak Grove	32.6 - 49.0	Baylor No. 1	1.8 - 2.7
Pinnacle No. 50	32.4 - 48.6	Bowie No. 1	1.8 - 2.7
Blue Creek No. 4	32.2 - 48.4	Old Ben No. 24	1.8 - 2.7
Enlow Fork	21.7 - 32.6	Clean Energy No. 1	1.7 - 2.5
Federal No. 2	21.7 - 32.6	Meigs No. 31	1.7 - 2.5
VP No. 3	21.1 - 31.6	Warwick	1.7 - 2.5
Cumberland	16.6 - 24.9	McClure No. 2	1.5 - 2.3
Blacksville No. 2	15.2 - 22.7	Old Ben No. 25	1.5 - 2.3
Blue Creek No. 5	15.0 - 22.6	Arch No. 37	1.5 - 2.2
Emerald No. 1	14.6 - 22.0	Camp No. 11	1.4 - 2.0
Cambria No. 33	14.4 - 21.6	Pontiki No. 2	1.4 - 2.0
Galatia No. 56	13.5 - 20.2	Tanoma	1.4 - 2.0
Shoal Creek	12.6 - 18.9	Urling No.1	1.4 - 2.0
Bailey	12.4 - 18.6	Wolf Creek No. 4	1.3 - 1.9
Humphrey No. 7	11.6 - 17.4	Brushy Creek	1.2 - 1.8
Golden Eagle	11.4 - 17.0	Crown II	1.1 - 1.6
Loveridge No. 22	11.1 - 16.7	Freedom Energy No. 1	1.1 - 1.6
Wabash	7.1 - 10.7	Maple Creek	1.1 - 1.6
Robinson Run No. 95	6.8 - 10.2	Nelms Cadiz Portal	1.1 - 1.6
Sanborn Creek	6.8 - 10.2	Orient No. 6	1.1 - 1.6
Dilworth	6.3 - 9.5	Pinnacle	1.1 - 1.6
Mine 84	6.2 - 9.3	Dotiki	1.0 - 1.5
West Elk	6.2 - 9.3	Deserado	1.0 - 1.5
Maple Meadow No. 1	5.9 - 8.9	Eagle Nest	0.9 - 1.4
McElroy	5.2 - 7.7	Pontiki No. 1	0.8 - 1.3
Soldier Canyon	5.2 - 7.7	Bullitt	0.8 - 1.1
Wheatcroft No. 9	5.1 - 7.6	Meigs No. 2	0.8 - 1.1
North River No. 1	4.5 - 6.8	Monterey No. 1	0.8 - 1.1
Arkwright No. 1	4.0 - 6.1	Monterey No. 2	0.6 - 0.9
Shoemaker	3.8 - 5.7	Buck Creek	0.6 - 0.9
McClure No. 1	3.6 - 5.5	Powhatan No. 6	0.6 - 0.9
Sentinel	3.6 - 5.5	Southfield	0.6 - 0.9
Rend Lake	3.3 - 5.0	Cimarron	0.5 - 0.7
Baker	2.8 - 4.2	Elkhart	0.5 - 0.7
Pattiki	2.6 - 3.9	Windsor	0.5 - 0.7

¹ Based on latest year for which data is available.² Range is calculated assuming that from 40% to 60% of total liberated methane could be recovered. For this table, this range is used for all of the mines regardless of the assumed current drainage efficiency (which is 0% for those mines that do not already have a drainage system in place).

Table 19: Mines Listed by Potential Electric Generating Capacity¹

MINE NAME	MEGAWATTS²	MINE NAME	MEGAWATTS²
Grove No. 1	0.2 - 0.2		

¹ Based on latest year for which data is available.

² Range is calculated assuming that from 40% to 60% of total liberated methane could be recovered. For this table, this range is used for all of the mines regardless of the assumed current drainage efficiency (which is 0% for those mines that do not already have a drainage system in place).

Table 20: Mines Listed by Potential Annual Gas Sales¹

MINE NAME	BCF/YR²	MINE NAME	BCF/YR²
Blue Creek No. 7	4.5 - 6.7	Powhatan No. 4	0.2 - 0.4
Buchanan No. 1	4.4 - 6.6	Old Ben No. 26	0.2 - 0.4
VP No. 8	3.6 - 5.5	Mary Lee No. 1	0.2 - 0.3
Blue Creek No. 3	3.5 - 5.3	Aberdeen	0.2 - 0.3
Pinnacle No. 50	3.1 - 4.7	Baylor No. 1	0.2 - 0.3
Blue Creek No. 4	3.1 - 4.7	Bowie No. 1	0.2 - 0.3
Oak Grove	3.1 - 4.7	Old Ben No. 24	0.2 - 0.3
Enlow Fork	2.1 - 3.1	Clean Energy No. 1	0.2 - 0.2
Federal No. 2	2.1 - 3.1	Meigs No. 31	0.2 - 0.2
VP No. 3	2.0 - 3.0	Warwick	0.2 - 0.2
Cumberland	1.6 - 2.4	McClure No. 2	0.1 - 0.2
Blacksville No. 2	1.5 - 2.2	Old Ben No. 25	0.1 - 0.2
Blue Creek No. 5	1.4 - 2.2	Arch No. 37	0.1 - 0.2
Emerald No. 1	1.4 - 2.1	Camp No. 11	0.1 - 0.2
Cambria No. 33	1.4 - 2.1	Pontiki No. 2	0.1 - 0.2
Galatia No. 56	1.3 - 1.9	Tanoma	0.1 - 0.2
Shoal Creek	1.2 - 1.8	Urling No. 1	0.1 - 0.2
Bailey	1.2 - 1.8	Wolf Creek No. 4	0.1 - 0.2
Humphrey No. 7	1.1 - 1.7	Brushy Creek	0.1 - 0.2
Golden Eagle	1.1 - 1.6	Crown II	0.1 - 0.2
Loveridge No. 22	1.1 - 1.6	Freedom Energy No. 1	0.1 - 0.2
Wabash	0.7 - 1.0	Maple Creek	0.1 - 0.2
Robinson Run No. 95	0.7 - 1.0	Nelms Cadiz Portal	0.1 - 0.2
Sanborn Creek	0.7 - 1.0	Orient No. 6	0.1 - 0.2
Dilworth	0.6 - 0.9	Pinnacle	0.1 - 0.2
Mine 84	0.6 - 0.9	Dotiki	0.1 - 0.1
West Elk	0.6 - 0.9	Deserado	0.1 - 0.1
Maple Meadow No. 1	0.6 - 0.9	Eagle Nest	0.1 - 0.1
McElroy	0.5 - 0.7	Pontiki No. 1	0.1 - 0.1
Soldier Canyon	0.5 - 0.7	Bullitt	0.1 - 0.1
Wheatcroft No. 9	0.5 - 0.7	Meigs No. 2	0.1 - 0.1
North River No. 1	0.4 - 0.7	Monterey No. 1	0.1 - 0.1
Arkwright No. 1	0.4 - 0.6	Monterey No. 2	0.1 - 0.1
Shoemaker	0.4 - 0.5	Buck Creek	0.1 - 0.1
McClure No. 1	0.4 - 0.5	Powhatan No. 6	0.1 - 0.1
Sentinel	0.4 - 0.5	Southfield	0.1 - 0.1
Rend Lake	0.3 - 0.5	Cimarron	0.0 - 0.1
Baker	0.3 - 0.4	Elkhart	0.0 - 0.1
Pattiki	0.2 - 0.4	Windsor	0.0 - 0.1

¹ Based on latest year for which data is available.

² Range is calculated assuming that 40% to 60% of total liberated methane could be recovered. For this table, this range is used for all of the mines regardless of the assumed current drainage efficiency (which is 0% for those mines that do not already have a drainage system in place).

Table 20: Mines Listed by Potential Annual Gas Sales¹

MINE NAME	BCF/YR ²	MINE NAME	BCF/YR ²
Grove No. 1	0.0 - 0.0		

¹ Based on latest year for which data is available.

² Range is calculated assuming that 40% to 60% of total liberated methane could be recovered. For this table, this range is used for all of the mines regardless of the assumed current drainage efficiency (which is 0% for those mines that do not already have a drainage system in place).

6. Profiled Mines

Data Summary

Below is a state-by-state summary of data pertaining to coal mine methane at profiled mines. Chapter 4 explains how these data were derived. Following this data summary section are individual mine profiles, in alphabetical order by state.

Alabama

Of the fourteen profiled U.S. mines that already recover and use methane, six are located in Alabama. Four of these mines are owned by Jim Walter Resources (JWR), one mine is owned by U.S. Steel Mining, and one mine is owned by Drummond Coal. All six mines sell methane to pipelines. Based on information obtained from various sources (Lasseter et. al., 1996; Walter Industries Inc., 1996; GeoMet, 1997a; GeoMet, 1997b) the six mines recovered and sold an average of 59 mmcf/d in 1996. Most of this recovery was from areas that are currently or will eventually be mined. The only known exception is that a portion of the 9.7 mmcf/d recovered from the Shoal Creek Mine is from non-mining areas. Therefore, in Table 6-1 the reason that "Estimated Methane Drained" from mines that use methane (52.1 mmcf/d) is less than "Estimated Methane Used" (59.0 mmcf/d) is that the latter figure includes methane drainage from areas of the Shoal Creek Mine that will not be mined. The former figure estimates only the amount of methane drained from areas that will be mined.

In addition to these mines, Alabama has two other large gassy mines that appear to be good candidates for methane recovery projects. Both mines use the longwall mining method. North River No. 1 has been in operation since 1974. Table 6-1 shows that the implementation of a methane recovery and use project at the North River No. 1 Mine could reduce annual methane emissions by 0.4-0.7 bcf/yr.

Mary Lee No. 1, which also began operations in 1974, is expected to close in 1997. Despite its closure, however, methane recovery from Mary Lee No. 1 may still remain a viable option.

Table 6-1: Alabama Mines

Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation, Drainage and Use Data ¹				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Using Mines (mines at which recovery and use projects have already been developed):							
Blue Creek No. 3	Jim Walter Res.	2.0	13.0	11.0	24.0	4,428.0	NA
Blue Creek No. 4	Jim Walter Res.	2.4	11.5	9.8	21.3	3,221.0	NA
Blue Creek No. 5	Jim Walter Res.	0.6	5.4	4.6	9.9	5,853.0	NA
Blue Creek No. 7	Jim Walter Res.	<u>2.4</u>	<u>16.6</u>	<u>14.1</u>	<u>30.7</u>	4,638.0	<u>NA</u>
Subtotal for Jim Walter Res. Mines		7.4	46.5	39.5	85.9	-	40.0
Oak Grove	U.S. Steel	3.0	12.3	9.3	21.5	2,627.0	9.3
Shoal Creek	Drummond	<u>3.4</u>	<u>5.0</u>	<u>3.3</u>	<u>8.3</u>	900.7	<u>9.7²</u>
Total for All Mines Using Methane		13.8	63.8	52.1	115.8	-	59.0 ²
Operating But Not Using Methane:							
North River No. 1	Pitts. & Midway	2.1	3.0	0.0	3.0	532.3	0.0
Closing Mine, Not Using Methane:							
Mary Lee No. 1	Drummond	1.2	1.5	0.0	1.5	462.0	0.0
TOTAL: ³		17.0	68.3	52.1	120.3	-	59.0

Estimated Emissions and Avoided Emissions of Methane and CO ₂ Equivalent From Operating Mines Not Currently Using Methane (North River No. 1):		Methane (bcf/yr)	CO ₂ (mmt/yr)
1996 Estimated Total Emissions		1.1	0.5
Estimated Annual Avoided Emissions if Recovery Project is Implemented		0.4-0.7	0.2 - 0.3

¹ Chapter 4 explains how these were estimated.

² Includes methane drained from areas that will not be mined in the future.

³ Values shown here do not always sum to totals due to rounding.

Colorado

Colorado has a number of underground mines with relatively low methane emissions, but it also has several deep and gassy mines with high emissions; these mines present potential opportunities for those interested in developing a methane recovery project in the West.

In 1997, a methane recovery project began at the Golden Eagle Mine. The mine, owned by Basin Resources, has been closed since December 1995. Stroud is recovering about 1.5 mmcf/d from vertical methane drainage boreholes that Basin Resources had drilled when the mine was operating. Stroud is marketing the gas via the Colorado Interstate Gas pipeline system.

Colorado has five operating mines that are potential candidates for methane recovery: Bowie No. 1 (formerly Orchard Valley), Deserado, Sanborn Creek, Southfield, and West Elk. Table 6-2 shows coal production, methane ventilation, and drainage data.

Table 6-2: Colorado Mines						
Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation and Drainage Data ¹			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which recovery and use projects have already been developed):						
Golden Eagle (Closed)	Basin Resources	0.0	0.0	0.0	0.0	0.0
(Methane use did not begin at Golden Eagle until 1997; mine produced 1.5 mmcf/d in 1997)						
Operating But Not Using Methane:						
Bowie No. 1	Bowie Resources	0.6	1.2	0.0	1.2	722.8
Deserado	Western Fuels	0.5	0.4	0.3	0.7	459.1
Sanborn Creek	Pacific Basin Res.	1.2	4.5	0.0	4.5	1,419.5
Southfield	Energy Fuels Coal	0.2	0.4	0.0	0.4	858.8
West Elk	Mountain Coal	<u>5.9</u>	<u>4.1</u>	<u>0.0</u>	<u>4.1</u>	251.6
Total:²		8.4	10.6	0.3	10.9	-
TOTAL:²		8.4	10.6	0.3	10.9	-
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (five mines):					Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions						4.0
Estimated Annual Avoided Emissions if Recovery Projects are Implemented						1.6 - 2.4
						1.8
						0.7-1.1

¹ Chapter 4 explains how these data were estimated.

² Values shown here do not always sum to totals due to rounding.

¹ Chapter 4 explains how these data were estimated.

² Values shown here do not always sum to totals due to rounding.

Among the five operating mines, Sanborn Creek and West Elk had the highest methane emissions, totaling 4.5 and 4.1 mmcf/d, respectively, in 1996. In April 1996, the West Elk Mine set a world production record for a single longwall operation. Deserado, which ranks fourth out of the five operating mines in terms of 1996 methane emissions, is the only mine of the five with a degasification system.

Table 6-2 shows that the implementation of methane recovery and use projects at the five mines that are operating but not using methane could reduce annual methane emissions by 1.6-2.4 bcf/yr.

Illinois

In general, Illinois mines tend to be less gassy than mines in other regions of the country. These mines tend to have lower specific emissions, but many have high total methane emissions depending on their yearly coal production. Accordingly, large emissions reductions may be achieved at some of these mines. Coal production and methane ventilation and drainage data on these mines are shown in Table 6-3.

Nine operating Illinois mines are considered to be potential candidates for methane recovery projects. Additionally, four Illinois mines that have been closed or idled may also be

candidates for methane recovery. None of the featured Illinois mines have a degasification system in place.

Table 6-3: Illinois Mines						
Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation and Drainage Data ¹			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which recovery and use projects have already been developed):						
None						
Operating But Not Using Methane:						
Brushy Creek	Western Fuels	0.6	0.8	0.0	0.8	506.1
Crown II	Freeman United	1.7	0.7	0.0	0.7	147.7
Elkhart	Zeigler	2.0	0.3	0.0	0.3	55.3
Galatia No. 56	Kerr-McGee	6.5	8.9	0.0	8.9	498.2
Monterey No. 1	Monterey Coal	2.4	0.5	0.0	0.5	75.1
Orient No. 6	Freeman United	1.1	0.7	0.0	0.7	229.8
Pattiki	MAPCO	1.8	1.7	0.0	1.7	345.5
Rend Lake	CONSOL	3.2	2.2	0.0	2.2	252.0
Wabash	Cyprus Amax	<u>3.2</u>	<u>4.7</u>	<u>0.0</u>	<u>4.7</u>	529.6
Total²:		22.6	20.5	0.0	20.5	-
Closed/Idle Mines, Not Using Methane:						
Monterey No. 2	Monterey Coal	1.7	0.4	0.0	0.4	88.3
Old Ben No. 24	Old Ben Coal	0.5	1.2	0.0	1.2	877.8
Old Ben No. 25	Old Ben Coal	0.0	0.0	0.0	0.0	0.0
Old Ben No. 26	Old Ben Coal	<u>3.1</u>	<u>1.6</u>	<u>0.0</u>	<u>1.6</u>	186.2
Total:²		5.3	3.2	0.0	3.2	-
TOTAL²:		27.9	23.7	0.0	23.7	-
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (nine mines):					Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions					7.5	3.3
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					3.0 - 4.5	1.3 - 2.0
¹ Chapter 4 explains how these data were estimated.						
² Values shown here do not always sum to totals due to rounding.						

One factor that may impact the desirability of Illinois coal mines as potential candidates is that, in comparison to other coal mining regions, coal produced from mines in the Illinois Basin tends to have a high sulfur content. Accordingly, many Illinois mines have been severely affected as a result of the implementation of sulfur dioxide emissions controls under the 1990 Clean Air Act Amendments. A number of Illinois mines have closed or reduced production as a result of their utility customers' switching to low-sulfur coals. This factor was largely

responsible for the closure of the Old Ben No. 24 and Old Ben No. 26 mines, as well as the idling of the Monterey No. 2 Mine. The Old Ben No. 25 Mine, which closed in 1994, was reopened in 1996 as the site of the National Museum of Coal Mining and is a non-producing mine. While some of the mines profiled in this report will likely reduce production over the next few years, others may be in a more secure position because they produce coal with a relatively low sulfur content. Moreover, there is good potential for recovery of methane from abandoned mines; at least one such project using coalbed methane to heat a greenhouse has have already been developed in Illinois. The project is not profiled in this report because the mine, Peabody 46, is not emitting significant quantities of methane to the atmosphere.

Table 6-3 shows that the implementation of methane recovery and use projects at the nine profiled mines that are operating but not using methane could reduce annual methane emissions by 3.0 - 4.5 bcf/yr.

Indiana

A single Indiana mine, Buck Creek, is profiled in this report. This room-and-pillar operation, which is considered the largest underground mine in Indiana, was idled in December 1995 following the loss or expiration of key contracts. During 1996, the mine's owner, Buck Creek Coal Company, declared Chapter 7 involuntary bankruptcy, which was then converted to Chapter 11 bankruptcy. At the end of 1996, Orion Diversified Technologies was preparing to purchase the mine and had already identified two customers for Buck Creek's coal, but the purchase eventually fell through.

The mine reported total methane emissions of nearly 110 million cubic feet in 1996, and is not equipped with a degasification system. Based on these emissions, a methane project may remain viable at Buck Creek.

Kentucky

Kentucky has eight operating mines that are good candidates for the development of methane recovery projects. Additionally, two recently closed mines may also be potential candidates. Coal production, methane ventilation and drainage data on these mines are shown in Table 6-4.

The Baker and Wheatcroft No. 9 mines, which are located in the western Kentucky portion of the Illinois Coal Basin, are part of one complex owned by the Renco Group. The Camp No. 11 and Dotiki mines are also located in the Illinois Coal Basin. The Freedom Energy No. 1, Arch No. 37, Clean Energy No. 1, Pontiki No. 1, Pontiki No. 2, and Wolf Creek mines are located in eastern Kentucky, in the Central Appalachian Basin. In general, coal produced from mines in western Kentucky tends to have a higher sulfur content than does coal produced from eastern Kentucky mines. For example, as shown in the mine profiles and summary tables, the sulfur content of the candidate mines in western Kentucky ranges from about 1.8 to 2.9 percent, whereas the sulfur content for the eastern Kentucky mines ranges from 0.6 to 2.6 percent.

Table 6-4 shows that methane emissions from the eight operating Kentucky mines totaled an estimated 2.8 bcf in 1996. Implementation of methane recovery and use projects at these eight mines could reduce annual methane emissions by an estimated 1.1 - 1.7 bcf/yr.

Table 6-4: Kentucky Mines						
Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation and Drainage Data ¹			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which recovery and use projects have already been developed):						
None						
Operating But Not Using Methane:						
Arch No. 37	Arch Mineral	4.6	1.0	0.0	1.0	77.1
Baker	Renco Coal Group	5.9	1.9	0.0	1.9	115.0
Camp No. 11	Peabody	3.1	0.9	0.0	0.9	106.1
Clean Energy No. 1	A.T. Massey	1.3	1.1	0.0	1.1	312.2
Dotiki	MAPCO	3.3	0.7	0.0	0.7	73.9
Freedom Energy No. 1	Sidney Coal Company	1.1	0.7	0.0	0.7	232.0
Pontiki No. 1	MAPCO	1.2	0.6	0.0	0.6	176.8
Pontiki No. 2	MAPCO	<u>0.8</u>	<u>0.9</u>	<u>0.0</u>	<u>0.9</u>	408.1
Total:²		21.3	7.7	0.0	7.7	-
Closed Mines, Not Using Methane:						
Wheatcroft No. 9	Renco Coal Group	0.0	0.1	0.0	0.1	-
Wolf Creek No. 4	Zeigler	<u>0.0</u>	<u>0.4</u>	<u>0.0</u>	<u>0.4</u>	0.0
Total:²		0.0	0.5	0.0	0.5	-
TOTAL:²		21.3	8.2	0.0	8.2	-
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (eight mines):					Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions					2.8	1.2
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					1.1 - 1.7	0.5 - 0.7
¹ Chapter 4 explains how these data were estimated.						
² Values shown here do not always sum to totals due to rounding.						

New Mexico

The Cimarron Mine, which is owned by the Pittsburgh & Midway Coal Mining Co., is the only New Mexico mine profiled in this report. This longwall mine was closed in October 1995 as a result of difficult geological conditions.

In 1995, the mine reported total methane emissions of nearly 110 million cubic feet. Based on these emissions, a coalbed methane project may still be possible.

Ohio

Five operating Ohio mines are profiled in this report: Meigs No. 2, Meigs No. 31, Nelms-Cadiz Portal, Powhatan No. 4, and Powhatan No. 6. Coal production, ventilation, and drainage data on these mines are shown in Table 6-5.

Table 6-5: Ohio Mines						
Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation and Drainage Data ¹			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which recovery and use projects have already been developed):						
None ²						
Operating But Not Using Methane:						
Meigs No. 2	Southern Ohio Coal	2.9	0.5	0.0	0.5	62.0
Meigs No. 31	Southern Ohio Coal	3.0	1.1	0.0	1.1	133.5
Nelms-Cadiz Portal ²	Harrison Mining	1.1	0.7	0.0	0.7	230.0
Powhatan No. 4	CONSOL	3.4	1.7	0.0	1.7	183.4
Powhatan No. 6	Ohio Valley Coal	<u>4.7</u>	<u>0.4</u>	<u>0.0</u>	<u>0.4</u>	30.8
Total:³		15.1	4.4	0.0	4.4	-
Closed/Idle Mines, Not Using Methane:						
None						
TOTAL:³		15.1	4.4	0.0	4.4	-
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (all five mines):					Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions					1.6	0.7
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					0.6 - 1.0	0.3 - 0.4
¹ Chapter 4 explains how these data were estimated.						
² As discussed in the text, the Nelms-Cadiz Portal Mine uses electricity generated from methane drained from the adjacent Nelms No. 1 Mine (about 0.18 mmcf/d).						
³ Values shown here do not always sum to totals due to rounding.						

The Meigs No. 2 and Meigs No. 31 mines both supply the Gavin power plant operated by American Electric Power, and both mines are expected to operate until 2009. The Meigs No. 31 Mine is currently the largest mine in Ohio. Powhatan No. 4 is owned by CONSOL and Powhatan No. 6 is owned by Ohio Valley Coal. The Nelms-Cadiz Portal Mine purchases electricity generated from methane drained at Nelms No. 1 Mine, which is permanently closed¹. Methane drainage from Nelms No. 1 for this purpose is about 0.18 mmcf/d.

¹ This report does not profile the Nelms No. 1 mine because it is permanently sealed and does not emit significant quantities of methane to the atmosphere. Page 3-6 describes the electricity generation project.

Table 6-5 shows that the implementation of methane recovery and use projects at these five Ohio mines could reduce annual methane emissions by 0.6 - 1.0 bcf/yr.

Pennsylvania

Ten operating Pennsylvania mines are good candidates for methane recovery and use and are profiled in this report. Additionally, the report profiles one mine that has recently closed and one mine that was recently idled. These mines may also be candidates for methane projects. Coal production, ventilation, and drainage data on these mines are shown in Table 6-6.

Table 6-6: Pennsylvania Mines						
Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation and Drainage Data ¹			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which methane recovery and use projects have already been developed):						
None						
Operating But Not Using Methane:						
Bailey	CONSOL	7.5	4.9	3.3	8.2	399.5
Cumberland	Cyprus Amax	5.2	9.3	1.6	10.9	768.0
Dilworth	CONSOL	4.8	2.5	1.7	4.2	314.1
Emerald No. 1	Cyprus Amax	3.2	5.8	3.9	9.7	1,092.0
Enlow Fork	CONSOL	8.7	8.6	5.7	14.3	599.8
Grove No. 1	Lion Mining	0.5	0.1	0.0	0.1	78.5
Maple Creek	Maple Creek Mining	3.4	0.0	0.0	1.2	125.2
Mine 84	Eighty Four Mining	3.0	4.1	0.0	4.1	494.6
Tanoma	Tanoma Mining Co.	0.6	0.9	0.0	0.9	588.7
Urling No. 1	Rochester & Pitts.	<u>0.9</u>	<u>0.0</u>	<u>0.0</u>	<u>1.5</u>	633.0
Total:²		37.8	37.8	16.2	54.0	-
Closed /Idle Mines, Not Using Methane:						
Warwick	Duquesne Light	1.9	1.1	0.0	1.1	213.6
Cambria No. 33	BethEnergy Mines	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	0.0
Total:²		1.9	1.1	0.0	1.1	-
TOTAL:²		39.7	38.9	16.2	55.1	-
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (ten mines):					Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions					19.7	9.0
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					7.9 - 11.8	3.6 - 5.4
¹ Chapter 4 explains how these data were estimated.						
² Values shown here do not always sum to totals due to rounding.						

In 1996, the ten operating mines shown in Table 6-6 liberated about 54.0 mmcf/d (19.7 bcf/yr) of methane. Several of these mines are located in Greene County, Pennsylvania. In fact, Greene County is the location of the two largest underground mines in the United States, CONSOL's Bailey and Enlow Fork mines. These mines are adjacent to one another and are often referred to as the Bailey-Enlow Fork complex. The Bailey Mine began operations in 1985, and the Enlow Fork Mine began operations in 1990. In 1996, Enlow Fork produced 8.7 million tons of coal, and Bailey produced 7.5 million tons. In 1996, Enlow Fork alone emitted 14.3 mmcf/d, or nearly 600 cf of methane per ton of coal produced. Both Bailey and Enlow Fork have drainage systems in place.

Two other large and gassy mines are also located in Greene County, Cyprus Amax's Emerald No. 1 and Cumberland mines. As with Bailey and Enlow Fork, Emerald and Cumberland are located in close proximity to each other. Together, these two mines emitted 20.6 mmcf/d (7.5 bcf/yr). Both mines are very gassy; estimated specific emissions are 1,092 cf/ton for the Emerald No. 1 Mine and 768.0 cf/ton for the Cumberland Mine. Both mines already have drainage systems in place, although the methane is not being used at present. Cyprus Amax's Cumberland Mine currently drains between 60,000 and 149,000 cubic feet of gas per day from its vertical pre-mine wells. Cumberland plans to continue its vertical and horizontal well program, as it is proving effective in reducing methane build-up in the mine.

Table 6-6 shows that the implementation of recovery and use projects at the ten profiled Pennsylvania mines that are currently operating could reduce annual methane emissions by 7.9-11.8 bcf/yr.

Utah

The Soldier Canyon Mine, owned by the Soldier Creek Coal Company, had been recovering methane for pipeline sales since the early 1980's, but its methane recovery operations ended in 1994 when mining progressed into an area of relatively non-gassy coal. It is unlikely that methane recovery will be initiated again soon at this mine since many of the compressor stations and associated equipment that is required for methane recovery and use have been dismantled. When the mine was recovering methane, it used long-hole horizontal boreholes to recover approximately 50 percent of the methane that would otherwise have been released to the atmosphere. In 1996, this mine liberated 3.40 mmcf/d (1.25 bcf/yr) of methane (Table 6-7).

In addition to the Soldier Canyon Mine, this report profiles the Aberdeen and Pinnacle mines in Utah. Both mines are owned by Andalex Resources, and emitted a combined total of 1.6 mmcf/d (584 mmcf/yr) of methane in 1996.

Table 6-7 shows that the implementation of methane recovery and use projects at the Aberdeen and Soldier Canyon mines could reduce annual methane emissions by 0.7 - 1.0 bcf/yr.

Table 6-7: Utah Mines						
Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation and Drainage Data ¹			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (est.) (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which recovery and use projects have already been developed):						
None						
Operating But Not Using Methane:						
Aberdeen	Andalex Resources	2.4	1.4	0.0	1.4	210
Soldier Canyon	Soldier Creek Coal	<u>1.0</u>	<u>3.4</u>	<u>0.0</u>	<u>3.4</u>	1,271
Total:²		3.4	4.8	0.0	4.8	
Closed Mine, Not Using Methane:						
Pinnacle	Andalex Resources	0.0	0.2	0.0	0.2	0
TOTAL:²		3.4	5.0	0.0	5.0	-
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (two mines):					Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions					1.7	0.8
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					0.7 - 1.0	0.3 - 0.5
¹ Chapter 4 explains how these data were estimated.						
² Values shown here do not always sum to totals due to rounding.						

Virginia

As Table 6-8 demonstrates, three of the mines at which successful methane recovery and use projects have already been developed are located in Virginia. The Buchanan No. 1, VP No. 3, and VP No. 8 mines are all longwall operations, and are all owned by subsidiaries of CONSOL. The total methane drained at these three CONSOL Virginia mine properties equaled or surpassed 73 mmcf/d in 1996 (Virginia Gas and Oil Board, 1997a; CONSOL, 1997) and increased to 85 mmcf/d in 1997 (CONSOL, 1997). This number significantly exceeds ventilation emissions of 32.9 mmcf/d, which indicates that much of the produced gas comes from virgin coals that the coal company may mine in the future, and/or that recovery efficiencies are higher than standard EPA assumptions.

Of the 85 mmcf/d of methane that CONSOL currently recovers, a small fraction, approximately 1.5 mmcf/d, is being used on site in a thermal dryer. The remaining amount is sold to a pipeline. Of the total recovered methane, gob wells account for approximately 65 percent of production, vertical wells account for approximately 22 percent of production, in-mine boreholes account for 3 percent of production, and releases from sealed areas account for the remaining 10 percent of production.

Table 6-8: Virginia Mines						
Mine	Company	1996 Coal Production (mm tons)	1996 Ventilation and Drainage Data ¹			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which recovery and use projects have already been developed):						
Buchanan No. 1	CONSOL	3.6	12.8	NA	NA	NA
VP No. 3	CONSOL	1.6	6.9	NA	NA	NA
VP No. 8	CONSOL	<u>2.8</u>	<u>13.2</u>	<u>NA</u>	<u>NA</u>	NA
Total: ²		8	32.9	NA	NA	-
Estimated Methane Used From Above Mines in 1996: 73 mmcf/d						
Operating But Not Using Methane:						
McClure No. 2	Clinchfield Coal	0.4	1.0	0.0	1.0	1,005.5
Closed/Closing, Not Using Methane:						
McClure No. 1	Clinchfield Coal	0.0	1.4	0.0	1.4	0.0
Bullitt	Westmoreland	<u>0.0</u>	<u>0.5</u>	<u>0.0</u>	<u>0.5</u>	0.0
Total:		0.0	1.9	0.0	1.9	-
TOTAL: ³		8.3	35.8	NA	NA	-
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (McClure No. 2):					Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions					0.4	0.2
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					0.1 - 0.2	0.08 - 0.12

¹ Chapter 4 explains how these data were estimated.

² See explanation in text above regarding apparent underestimate of volume of methane drained/liberated.

³ Values shown here do not always sum to totals due to rounding.

This report also profiles three other Virginia mines. Two of these mines, McClure No. 1 and McClure No. 2, are owned by mining companies that are subsidiaries of the Pittston Coal Company. The McClure No. 1 Mine was idled in 1995 due to the poor market for metallurgical coal. The Bullitt Mine was idled in 1995, and its owner, Westmoreland Coal, is interested in selling the mine. These three mines liberated a total of 2.9 mmcf/d (1.1 bcf/yr) of methane in 1996, which is equivalent to 0.5 million tons of CO₂. Table 6-8 shows that if a methane recovery project were to be implemented at the McClure No. 2 Mine, it could reduce annual methane emissions by 140-220 mmcf. The McClure No. 1 and Bullitt mines are also candidates for methane projects.

West Virginia

Of the 79 mines profiled in this report, 14 are located in West Virginia. Of these mines, five are currently recovering methane for sale, eight are operating but do not recover methane, and one has recently been closed. Coal production, methane ventilation, and drainage data on these mines are shown in Table 6-9.

Table 6-9: West Virginia Mines

		1996 Ventilation, Drainage, and Use Data ¹					
Mine	Company	1996 Coal Production (mm tons)	Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Using Mines (mines at which recovery and use projects have already been developed):							
Blacksville No. 2	CONSOL	3.4	6.0	4.0	10.0	1,074.2	0.0 ²
Humphrey No. 7 (Closing)	CONSOL	3.3	4.6	3.1	7.7	849.8	0.0 ²
Loveridge No. 22 ³	CONSOL	3.1	4.4	2.9	7.3	875.3	0.0 ²
Federal No. 2	Peabody	4.6	8.6	5.7	14.3	1,141.8	1.4
Pinnacle No. 50	U.S. Steel	<u>4.1</u>	<u>10.7</u>	<u>10.7</u>	<u>21.4</u>	1,922.0	<u>0.5</u>
Total: ⁴		18.5	34.3	26.4	60.7	-	1.9
Operating But Not Using Methane:							
Baylor No. 1	Baylor	1.0	1.2	0.0	1.2	462.0	0.0
Eagle Nest	A. T. Massey	1.4	0.6	0.0	0.6	158.6	0.0
Maple Meadow No. 1	Cyprus Amax	1.5	3.9	0.0	3.9	944.6	0.0
McElroy	CONSOL	4.3	3.4	0.0	3.4	288.0	0.0
Robinson Run No. 95	CONSOL	4.2	2.7	1.8	4.5	390.1	0.0
Sentinel	Philippi	1.8	2.4	0.0	2.4	489.7	0.0
Shoemaker	CONSOL	4.4	2.5	0.0	2.5	207.0	0.0
Windsor	Windsor Coal	<u>1.4</u>	<u>0.3</u>	<u>0.0</u>	<u>0.3</u>	<u>76.2</u>	<u>0.0</u>
Total: ⁴		20.0	17.0	1.8	18.8	0.0	0.0
Closing Mine, Not Using Methane:							
Arkwright No. 1	CONSOL	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL: ⁴		38.5	51.4	28.2	79.5	-	1.9
Estimated Emissions and Avoided Emissions of Methane and CO₂ Equivalent From Operating Mines Not Currently Using Methane (McClure No. 2):						Methane (bcf/yr)	CO₂ (mmt/yr)
1996 Estimated Total Emissions						6.9	3.3
Estimated Annual Avoided Emissions if Recovery Projects are Implemented						2.7 - 4.1	1.3 - 2.0

¹ Chapter 4 explains how these data were estimated.

² Methane recovery did not begin until 1997; data on methane use will not be publicly available until 1998.

³ As of September, 1997 this mine was not yet recovering methane; recovery expected to begin in October, 1997.

⁴ Values shown here do not always sum to totals due to rounding.

The five profiled mines that are recovering methane for sale are Blacksville No. 2, Federal No. 2, Humphrey No. 7, Loveridge No. 22 and Pinnacle No. 50. (The methane recovery project involving the Blacksville No. 2, Humphrey No. 7, and Loveridge No. 22 mines is often considered a Pennsylvania project, for reasons explained in Chapter 3). In 1996, the

Blacksville No. 2, Humphrey No. 7 and Loveridge No. 22 mines liberated an estimated 25.0 mmcf/d (9.1 bcf/yr). In 1996, the Federal No. 2 Mine liberated an estimated 14.3 mmcf/d (5.2 bcf/yr), and the Pinnacle No. 50 Mine liberated an estimated 21.4 mmcf/d (7.8 bcf/yr).

Federal No. 2 recovered and sold about 0.5 mmcf/d (189,000 mcf/yr) in 1995 (the project is still underway, but more recent data are unavailable). Pinnacle sold about about 1.4 mmcf/d (506 mcf/yr) of methane to a gas marketing company in 1996. The project at Blacksville No. 2, Humphrey No. 7, and Loveridge No. 22 began in 1997.

Nine of the West Virginia mines profiled in this report are located in the Northern Appalachian Basin; six of these, including the Arkwright No. 1 Mine, which closed in late 1995 due to decreased demand for higher-sulfur coal are owned by subsidiaries of CONSOL. For similar reasons, CONSOL's Humphrey No. 7 Mine is closing in 1997. The remaining five operating mines that are profiled are located in the Central Appalachian Basin.

Table 6-9 shows that the implementation of methane recovery and use projects at the eight operating mines that do not already use methane could reduce annual methane emissions by 2.7 - 4.1 bcf/yr.

6. Profiled Mines (continued)

States with Candidate and Utilizing Mines:

Alabama

Colorado

Illinois

Indiana

Kentucky

New Mexico

Ohio

Pennsylvania

Utah

Virginia

West Virginia

6. Profiled Mines (continued)

Alabama Mines

Blue Creek No. 3
Blue Creek No. 4
Blue Creek No. 5
Blue Creek No. 7
Mary Lee No. 1
North River No. 1
Oak Grove
Shoal Creek

Updated: May 1997

Status: Open/Using

Blue Creek No. 3

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Blue Creek

County: Jefferson

CORPORATE INFORMATION

Current Owner: Jim Walter Resources

Parent Company: Walter Industries, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: No. 3 Mine

MINE ADDRESS

Contact Name: G. Richmond, Mine Manager

Phone Number: 205-554-6350

Mailing Address: 5290 Mud Creek Rd.

City: Adger

State: AL

ZIP: 35006

GENERAL INFORMATION

Number of Employees at Mine: 652

Mining Method: Longwall

Year of Initial Production: 1975

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 11

Sulfur Content of Coal Produced: 0.55% - 0.86%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,500

Depth to Seam (ft): 2,000

Seam Thickness (ft): 5.8

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.5	1.6	1.8	2.0
Estimated Total Methane Liberated (million cf/day):	21.3	19.3	23.4	24.0
Emissions from Ventilation Systems:	11.5	10.4	12.6	13.0
Estimated Methane Drained:	9.8	8.9	10.8	11.0
Estimated Specific Emissions (cf/ton):	5,017	4,297	4,619	4,428

Estimated Current Drainage Efficiency: 46%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 3 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	1.56	2.33
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	31.0%	46.4%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	7.1%	10.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	14.8	59.3
Mine Electricity Demand:	11.5	47.4
Prep Plant Electricity Demand:	3.4	11.9
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	36.3	318.3
Assuming 60% Recovery Efficiency: ¹	54.5	477.4

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	3.5
Assuming 60% Recovery Efficiency (Bcf): ¹	5.3
Description of Surrounding Terrain: Open Hills/Open High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line	
Distance to Pipeline (miles): 0.0	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: SNG Intrastate Pipeline	
Distance to Next Nearest Pipeline (miles): 4.6	Pipeline Diameter (inches): 12.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; current drainage efficiency shown on previous page.

Blue Creek No. 3 (continued)

Summary of Recent News

In August 1995, representatives of Cyprus Amax toured the JWR mines. The Chairman of Cyprus Amax Minerals at the time, Milt Ward, had stated that he wanted the Cyprus Amax coal company to grow to a 100-million-ton company in the near term. As such, he was looking for reasonable acquisitions (CO 8/28/95). CONSOL also toured the JWR mines in late 1995. JWR has, however, strongly denied claims that the company's mines are for sale (CO 11/13/96).

About 45% of the total production from the JWR mines is sold to Alabama Power. Much of the remaining 55% is sold to the export low-volatile metallurgical market (CO 1/13/95). Recently, though, Alabama Power has been buying out its term coal contracts with JWR to make room for replacement coal from other mines. Alabama Power cites lower coal prices from other mines, especially coal from mines in the Powder River Basin, as the reason for the buyouts. For example, in November 1995, Alabama Power bought out a term coal agreement with JWR, thereby making room for a replacement purchase from CONSOL's Rend Lake mine, among others. JWR has responded to this turn in events by shipping more coal to international customers (CO 11/6/95).

Jim Walter Resources' Blue Creek mines recover methane for pipeline sales. A more detailed discussion of these mines is included in the section on existing methane recovery projects.

Updated: May 1997

Status: Open/Using

Blue Creek No. 4

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Blue Creek

County: Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources

Parent Company: Walter Industries, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: No. 4 Mine

MINE ADDRESS

Contact Name: J.E. Cooley, Mine Manager

Phone Number: 205-554-6450

Mailing Address: 14730 Lock 17 Rd.

City: Brookwood

State: AL

ZIP: 35444

GENERAL INFORMATION

Number of Employees at Mine: 652

Mining Method: Longwall

Year of Initial Production: 1975

Primary Coal Use: Metallurgical

Mine Life Expectancy (years): 19

Sulfur Content of Coal Produced: 0.75%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): 1,950

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.4	2.3	2.5	2.4
Estimated Total Methane Liberated (million cf/day):	23.9	25.2	29.7	21.3
Emissions from Ventilation Systems:	12.9	13.6	16.0	11.5
Estimated Methane Drained:	11.0	11.6	13.6	9.8
Estimated Specific Emissions (cf/ton):	3,615	4,065	4,251	3,221

Estimated Current Drainage Efficiency: 46%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 4 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	1.38	2.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	20.9%	31.3%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	4.8%	7.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	18.1	72.3
Mine Electricity Demand:	14.0	57.9
Prep Plant Electricity Demand:	4.1	14.5
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	32.2	282.4
Assuming 60% Recovery Efficiency: ¹	48.4	423.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	3.1
Assuming 60% Recovery Efficiency (Bcf): ¹	4.7
Description of Surrounding Terrain:	Open Hills/Open High Hills
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Mine owns pipeline that connects to trans. line
Distance to Pipeline (miles):	0.0
Pipeline Diameter (inches):	NA
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	8.3
Pipeline Diameter (inches):	24.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; current drainage efficiency shown on previous page.

Blue Creek No. 4 (continued)

Summary of Recent News

In 1996, Jim Walter Resources wrote down the value of the Blue Creek No. 4 mine. At the time analysts speculated that this action was an effort to re-value the mine for possible sale. Jim Walter Resources, however, refuted that assertion saying that the write-down was prompted by new accounting standards for U.S. businesses (CO 4/8/96). Today, Blue Creek No. 4 is still owned and operated by Jim Walter Resources.

In August 1995, representatives of Cyprus Amax toured the JWR mines. The Chairman of Cyprus Amax Minerals at the time, Milt Ward, had stated that he wanted the Cyprus Amax coal company to grow to a 100-million-ton company in the near term. As such, he was looking for reasonable acquisitions (CO 8/28/95). CONSOL also toured the JWR mines in late 1995. JWR has, however, strongly denied claims that the company's mines are for sale (CO 11/13/96).

About 45% of the total production from the JWR mines is sold to Alabama Power. Much of the remaining 55% is sold to the export low-volatile metallurgical market (CO 1/13/95). Recently, though, Alabama Power has been buying out its term coal contracts with JWR to make room for replacement coal from other mines. Alabama Power cites lower coal prices from other mines, especially coal from mines in the Powder River Basin, as the reason for the buyouts. For example, in November 1995, Alabama Power bought out a term coal agreement with JWR, thereby making room for a replacement purchase from CONSOL's Rend Lake mine, among others. JWR has responded to this turn in events by shipping more coal to international customers (CO 11/6/95).

In November 1994, Blue Creek No. 4 set an Alabama state record when the mine produced 19,404 clean tons in one day (CO 1/23/95).

Jim Walter Resources' Blue Creek mines recover methane for pipeline sales. A more detailed discussion of these mines is included in the section on existing methane recovery projects.

Updated: May 1997

Status: Open/Using

Blue Creek No. 5

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Blue Creek

County: Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources

Parent Company: Walter Industries, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: No. 5 Mine

MINE ADDRESS

Contact Name: J. Beasley, Mine Manager

Phone Number: 205-554-6550

Mailing Address: 12792 Lock 17 Road

City: Brookwood

State: AL

ZIP: 35444

GENERAL INFORMATION

Number of Employees at Mine: 517

Mining Method: Longwall

Year of Initial Production: 1975

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 8

Sulfur Content of Coal Produced: 0.72% - 0.88%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): 2,200

Seam Thickness (ft): 8.3

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.3	0.6	1.5	0.6
Estimated Total Methane Liberated (million cf/day):	15.2	34.8	30.9	9.9
Emissions from Ventilation Systems:	8.2	18.8	16.7	5.4
Estimated Methane Drained:	7.0	16.0	14.2	4.6
Estimated Specific Emissions (cf/ton):	4,302	19,897	7,367	5,853

Estimated Current Drainage Efficiency: 46%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 5 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.64	0.97
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	37.9%	56.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	8.7%	13.0%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	4.6	18.6
Mine Electricity Demand:	3.6	14.9
Prep Plant Electricity Demand:	1.1	3.7
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	15.0	131.7
Assuming 60% Recovery Efficiency: ¹	22.6	197.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.4
Assuming 60% Recovery Efficiency (Bcf): ¹	2.2
Description of Surrounding Terrain: Open Hills/Open High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line	
Distance to Pipeline (miles): 0.0	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): 10.0	Pipeline Diameter (inches): 24.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; current drainage efficiency shown on previous page.

Blue Creek No. 5 (continued)

Summary of Recent News

The Blue Creek No. 5 mine has had a number of in-mine fires. Jim Walter Resources (JWR) has almost always solved the problem of in-mine fires by sealing the affected area of the mine and then moving the longwall. Due to a fire, in 1995, the longwall was assembled in the eastern reserves section of the No. 5 mine. In late March, 1997, Jim Walter Resources resumed longwall mining at its No. 5 mine (CO 4/8/96; CO 4/7/97).

In 1996, Jim Walter Resources wrote down the value of the Blue Creek No. 5 mine. At the time analysts speculated that this action was an effort to re-value the mine for possible sale, but Jim Walter Resources refuted that assertion saying that the write-down was prompted by new accounting standards for U.S. businesses (CO 4/8/96). Today, Blue Creek No. 5 is still owned and operated by Jim Walter Resources.

In August 1995, representatives of Cyprus Amax toured the JWR mines. The Chairman of Cyprus Amax Minerals at the time, Milt Ward, had stated that he wanted the Cyprus Amax coal company to grow to a 100-million-ton company in the near term. As such, he was looking for reasonable acquisitions (CO 8/28/95). CONSOL also toured the JWR mines in late 1995. JWR has, however, strongly denied claims that the company's mines are for sale (CO 11/13/96).

About 45% of the total production from the JWR mines is sold to Alabama Power. Much of the remaining 55% is sold to the export low-volatile metallurgical market (CO 1/13/95). Recently, though, Alabama Power has been buying out its term coal contracts with JWR to make room for replacement coal from other mines. Alabama Power cites lower coal prices from other mines, especially coal from mines in the Powder River Basin, as the reason for the buyouts. For example, in November 1995, Alabama Power bought out a term coal agreement with JWR, thereby making room for a replacement purchase from CONSOL's Rend Lake mine, among others. JWR has responded to this turn in events by shipping more coal to international customers (CO 11/6/95).

Jim Walter Resources' Blue Creek mines recover methane for pipeline sales. A more detailed discussion of these mines is included in the section on existing methane recovery projects.

Updated: May 1997

Status: Open/Using

Blue Creek No. 7

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Blue Creek

County: Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources

Parent Company: Walter Industries, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: No. 7 Mine

MINE ADDRESS

Contact Name: Rich Donnelly, Mine Manager

Phone Number: 205-481-6706

Mailing Address: 18069 Hannah Creek Road

City: Brookwood

State: AL

ZIP: 35444

GENERAL INFORMATION

Number of Employees at Mine: 650

Mining Method: Longwall

Year of Initial Production: 1975

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 24

Sulfur Content of Coal Produced: 0.58% - 0.70%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,500

Depth to Seam (ft): 1,700

Seam Thickness (ft): 5.1

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	2.3	2.3	2.4
Estimated Total Methane Liberated (million cf/day):	31.5	32.2	54.1	30.7
Emissions from Ventilation Systems:	17.0	17.4	29.2	16.6
Estimated Methane Drained:	14.5	14.8	24.9	14.1
Estimated Specific Emissions (cf/ton):	6,771	5,013	8,537	4,638

Estimated Current Drainage Efficiency: 46%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 7 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	1.99	2.99
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	32.4%	48.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	7.4%	11.1%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	18.2	72.6
Mine Electricity Demand:	14.0	58.1
Prep Plant Electricity Demand:	4.1	14.5
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	46.6	408.0
Assuming 60% Recovery Efficiency: ¹	69.9	612.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	4.5
Assuming 60% Recovery Efficiency (Bcf): ¹	6.7
Description of Surrounding Terrain: Open Hills/Open High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line	
Distance to Pipeline (miles): 0.0	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): 13.3	Pipeline Diameter (inches): 24.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; current drainage efficiency shown on previous page.

Blue Creek No. 7 (continued)

Summary of Recent News

In August 1995, representatives of Cyprus Amax toured the JWR mines. The Chairman of Cyprus Amax Minerals at the time, Milt Ward, had stated that he wanted the Cyprus Amax coal company to grow to a 100-million-ton company in the near term. As such, he was looking for reasonable acquisitions (CO 8/28/95). CONSOL also toured the JWR mines in late 1995. JWR has, however, strongly denied claims that the company's mines are for sale (CO 11/13/96).

About 45% of the total production from the JWR mines is sold to Alabama Power. Much of the remaining 55% is sold to the export low-volatile metallurgical market (CO 1/13/95). Recently, though, Alabama Power has been buying out its term coal contracts with JWR to make room for replacement coal from other mines. Alabama Power cites lower coal prices from other mines, especially coal from mines in the Powder River Basin, as the reason for the buyouts. For example, in November 1995, Alabama Power bought out a term coal agreement with JWR, thereby making room for a replacement purchase from CONSOL's Rend Lake mine, among others. JWR has responded to this turn in events by shipping more coal to international customers (CO 11/6/95).

Jim Walter Resources' Blue Creek mines recover methane for pipeline sales. A more detailed discussion of these mines is included in the section on existing methane recovery projects.

Updated: May 1997

Status: Closing

Mary Lee No. 1

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Mary Lee

County: Walker

CORPORATE INFORMATION

Current Owner: Drummond Company, Inc.

Parent Company: Drummond Company, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Jim Balcar, Mine Superintendent

Phone Number: 205-251-6153

Mailing Address: P.O. Box 1549

City: Jasper

State: AL

ZIP: 35501

GENERAL INFORMATION

Number of Employees at Mine: 568

Mining Method: Longwall

Year of Initial Production: 1974

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.60% - 0.90%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,650

Depth to Seam (ft): 600

Seam Thickness (ft): 3.6

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.5	1.4	1.2	1.2
Estimated Total Methane Liberated (million cf/day):	1.7	1.5	1.6	1.5
Emissions from Ventilation Systems:	1.7	1.5	1.6	1.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	402	403	457	462

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Mary Lee No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.10	0.15
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.5%	5.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.8%	1.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	8.9	35.6
Mine Electricity Demand:	6.9	28.4
Prep Plant Electricity Demand:	2.0	7.1
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	2.3	19.9
Assuming 60% Recovery Efficiency: ¹	3.4	29.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.3
Description of Surrounding Terrain: Open Hills/Open High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: SNG Intrastate Pipeline	
Distance to Pipeline (miles): 7.5	Pipeline Diameter (inches): 6.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Furniture and sporting goods manufacturing, poultry processing; hospitals, colleges, and other municipal buildings..

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Mary Lee No. 1 (continued)

Summary of Recent News

The Mary Lee No. 1 mine is owned by Drummond Company, Inc., and is located in Walker County, Alabama. The mine has been longwall equipped since the fall of 1994 (CW 4/3/95).

In January 1997, about 280 people were laid off at the Mary Lee No. 1 mine and the attendant Gorgas preparation plant. About 210 workers remained after the reduction in workforce. No specific reason was given for the layoffs, but this action is widely seen as a precursor to complete closure of the mine (CO 2/17/97).

The mine is reportedly expected to be closed in May 1997 when the longwall finishes mining its current panel (CO 2/17/97). The closure is occurring despite recent significant capital expenditures on a longwall in an effort to improve productivity. The combination of tough geological problems, high mining costs and poor market prospects were reasons cited by Drummond for closing the mine (CO 12/2/96).

Sales & Supply

Mary Lee No. 1's major customer is Alabama Power Company.

Updated: May 1997

Status: Operating

North River No. 1

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Pratt

County: Fayette

CORPORATE INFORMATION

Current Owner: Pittsburgh & Midway Coal Mining Co.

Parent Company: Chevron

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: F.G. Semancik, General Mine Manager

Phone Number: 205-333-4000

Mailing Address: P.O. Box 519

City: Berry

State: AL

ZIP: 35546

GENERAL INFORMATION

Number of Employees at Mine: 310

Mining Method: Longwall

Year of Initial Production: 1974

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.75% - 1.91%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,085

Depth to Seam (ft): 625

Seam Thickness (ft): 4.1 - 4.8

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.3	1.5	2.0	2.1
Estimated Total Methane Liberated (million cf/day):	2.4	2.2	2.8	3.0
Emissions from Ventilation Systems:	2.4	2.2	2.8	3.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	386	538	519	532

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

North River No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.19	0.29
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.8%	5.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.9%	1.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	15.4	61.7
Mine Electricity Demand:	11.9	49.4
Prep Plant Electricity Demand:	3.5	12.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	4.5	39.8
Assuming 60% Recovery Efficiency: ¹	6.8	59.7

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.4
Assuming 60% Recovery Efficiency (Bcf): ¹	0.7
Description of Surrounding Terrain: Open Hills/Open High Hills	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: City Of Berry	
Distance to Pipeline (miles): 0.4	Pipeline Diameter (inches): 2.0
Owner of Next Nearest Pipeline: SNG Intrastate Pipeline	
Distance to Next Nearest Pipeline (miles): 14.2	Pipeline Diameter (inches): 24.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

North River No. 1 (continued)

Summary of Recent News

The North River mine is located near Berry, Alabama. It is operated by The Pittsburgh & Midway (P&M) Coal Mining Company, the only major operator in Fayette County. P&M began doing business in Alabama in 1981 when it purchased a 50% interest in the North River mine from Republic Steel Corp. The company bought the remainder of North River in 1986 from LTV Corp. P&M owns 6 other mines in Colorado, Kentucky, New Mexico and Wyoming, and has a partnership operation in Indiana (Coal 7/95 p. 43), but North River is its only mine in Alabama.

Over 24 million tons of coal have been mined at North River since it opened in 1974, and the mine produced 2.3 and 1.5 million tons in 1993 and 1994, respectively. North River increased its production to 1.9 million tons of coal in 1995 (1997 Keystone Coal Industry Manual, p.277). The mine operates one longwall system and one continuous miner section for development. North River is a UMWA mine employing around 300 people.

North River produces medium-sulfur (around 2%) coal. Some Phase I utilities in the Clean Air Act Amendments that have not installed scrubbers are now no longer able to use North River's coal exclusively, forcing the mine to adjust its deliveries. For example, North River recently had to shift delivery from its longtime customer, Alabama Power's Gaston plant, the company's only Phase I plant. North River now has a 4.5-year, 1 million ton per year contract with Alabama Power's Gorgas plant (Coal 7/95 p. 43).

In January 1995, P&M, Norfolk Southern and Alabama Power instituted a new rail-truck intermodal shipping system for transporting coal from North River to the Gorgas plant. The system uses specially-designed COLTainer trains that hold four containers with 24 tons capacity in each. Shipments are moved by the COLTainer units from North River to an intermodal facility at Parrish, where it is transferred to special dump truck chassis and then trucked to the Gorgas facility (CW 3/6/95). The system was developed to eliminate the need for truck hauls through the small Alabama communities of Berry, Oakman and Parrish. The containers are electronically tagged allowing the mine and power plant to track their location (Coal 7/95 p. 43).

Sales & Supply

As mentioned previously, P&M and Alabama recently negotiated a new agreement whereby Alabama Power will purchase coal from North River for its Gorgas plant, rather than the Gaston plant. This new agreement is for 4.5 years at 1 million tons of coal per year (Coal 7/95 p. 43).

Updated: May 1997

Status: Open/Using

Oak Grove

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Blue Creek

County: Jefferson

CORPORATE INFORMATION

Current Owner: U.S. Steel Mining Co., Inc.

Parent Company: USX Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Paul D. Hafera, General Superintendent

Phone Number: 205-497-0180

Mailing Address: 8800 Oak Grove Mine Rd.

City: Adger

State: AL

ZIP: 35006

GENERAL INFORMATION

Number of Employees at Mine: 450

Mining Method: Longwall

Year of Initial Production: 1974

Primary Coal Use: Metallurgical

Mine Life Expectancy (years): 26

Sulfur Content of Coal Produced: 0.53%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): 1,250

Seam Thickness (ft): 5.2

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.4	2.6	2.5	3.0
Estimated Total Methane Liberated (million cf/day):	15.6	15.1	16.9	21.5
Emissions from Ventilation Systems:	8.9	8.6	9.7	12.3
Estimated Methane Drained:	6.7	6.5	7.3	9.3
Estimated Specific Emissions (cf/ton):	2,410	2,141	2,484	2,627

Estimated Current Drainage Efficiency: 43%

Drainage System Used: Vertical Pre-Mine, Vertical Gob

Oak Grove (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	1.40	2.10
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	17.0%	25.5%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	3.9%	5.8%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	22.5	89.8
Mine Electricity Demand:	17.4	71.8
Prep Plant Electricity Demand:	5.1	18.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	32.6	285.9
Assuming 60% Recovery Efficiency: ¹	49.0	428.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	3.1
Assuming 60% Recovery Efficiency (Bcf): ¹	4.7
Description of Surrounding Terrain:	Open Hills/Open High Hills
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Mine owns pipeline that connects to trans. line
Distance to Pipeline (miles):	0.0
Pipeline Diameter (inches):	NA
Owner of Next Nearest Pipeline:	SNG Intrastate Pipeline
Distance to Next Nearest Pipeline (miles):	3.8
Pipeline Diameter (inches):	12.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; current drainage efficiency shown on previous page.

Oak Grove (continued)

Summary of Recent News

The Oak Grove mine, which is located in Alabama, is one of two mining complexes owned and operated by U.S. Steel Mining Company. The other is Pinnacle No. 50 (Gary No. 50), which is located in West Virginia. The mine produces metallurgical coal, which is mostly used by U.S. Steel in its steel production operations. In 1994, the mine was granted ISO 9002 quality assurance certification (CO 4/8/96).

Throughout 1995, U.S. Steel Mining upgraded both the Oak Grove mine and the accompanying Concord preparation plant. U.S. Steel plans to increase production at Oak Grove to 3 million tons annually by using longwall mining. The Concord plant is being modified to increase capacity and to produce granular coal (CW 4/3/95). In late 1995, U.S. Steel installed a new, \$20 million granular-injection unit on its No. 8 blast furnace at Fairfield Works in Alabama. The blast furnace uses Oak Grove granular coal for fuel (CO 1/8/96).

The Oak Grove mine recovers methane for pipeline sale. A more detailed discussion of this mine's methane recovery and sale project is included in the section on existing methane recovery projects.

Sales & Supply

U.S. Steel has an agreement to sell Brazilian steel mills a total of 1.05 million tons of Oak Grove and Pinnacle No. 50 coal (CW 5/13/96). In 1995, Companhia Siderurgica Tubarao, a Brazilian steel mill bought 20,000 tons of Oak Grove spot coal (CW 10/2/95).

Updated: May 1997

Status: Open/Using

Shoal Creek

GEOGRAPHIC DATA

Basin: Warrior

State: AL

Coalbed: Mary Lee, Blue Creek

County: Jefferson

CORPORATE INFORMATION

Current Owner: Drummond Company, Inc.

Parent Company: Drummond Company, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Don Hendrickson, Longwall Superintendent

Phone Number: 205-491-6200

Mailing Address: 8488 Nancy Ann Bend Road

City: Adger

State: AL

ZIP: 35006

GENERAL INFORMATION

Number of Employees at Mine: 830

Mining Method: Longwall

Year of Initial Production: 1994

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.63% - 1.10%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,000

Depth to Seam (ft): 1,150

Seam Thickness (ft): 7.0 - 11.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.0	1.0	2.3	3.4
Estimated Total Methane Liberated (million cf/day):	1.3	2.5	5.8	8.3
Emissions from Ventilation Systems:	0.8	1.5	3.5	5.0
Estimated Methane Drained:	0.5	1.0	2.3	3.3
Estimated Specific Emissions (cf/ton):	0	887	933	901

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Shoal Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.54	0.81
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	6.1%	9.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.4%	2.1%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	25.3	101.3
Mine Electricity Demand:	19.6	81.0
Prep Plant Electricity Demand:	5.8	20.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	12.6	110.6
Assuming 60% Recovery Efficiency: ¹	18.9	165.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.2
Assuming 60% Recovery Efficiency (Bcf): ¹	1.8
Description of Surrounding Terrain: Open Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: SNG Intrastate Pipeline	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Shoal Creek (continued)

Summary of Recent News

Drummond's Shoal Creek mine became operational in April 1994. The mine is located in Jefferson County, Alabama, near the very gassy Jim Walter Resources mines. The production target for Shoal Creek is 4.5 million tons per year (CO 10/30/95). Much of this coal will be shipped to Alabama Power's Miller plant as part of a long-term contract between Alabama Power and Drummond Company, Inc. (CO 10/30/95; CW 1/23/95).

Initially, Shoal Creek used continuous miners to mine the vast reserves of coal. But, in March 1995, Drummond began operating the first longwall at Shoal Creek, thereby improving the productivity of the mine. Six months later, in September 1995, a second longwall became operational (CO 10/30/95; CW 4/3/95).

The Shoal Creek mine is currently recovering methane for sale. Additional information about the recovery project at this mine is included in the section on existing methane recovery projects.

Sales & Supply

Although Shoal Creek ships much of its tonnage to Alabama Power's Miller plant, other customers include Brazilian steel makers and other domestic utilities, including the Alabama Electric Cooperative (CW 1/9/95; CW 1/23/95; CW 11/13/95, CO 10/30/95; CW 4/3/95).

In December 1994, Brazilian steel maker, Companhia Siderurgica Tubarao bought 30,000 tons of spot coal (CW 1/9/95).

6. Profiled Mines (continued)

Colorado Mines

Bowie No. 1
Deserado
Golden Eagle
Sanborn Creek
Southfield
West Elk

Updated: May 1997

Status: Operating

Bowie No. 1

GEOGRAPHIC DATA

Basin: Western (Piceance)

State: CO

Coalbed: Basin D

County: Delta

CORPORATE INFORMATION

Current Owner: Bowie Resources

Parent Company: Bowie Resources

Previous Owner(s): Cyprus Orchard Valley Coal Corp., Colorado Westmoreland

Previous or Alternate Name of Mine: Orchard Valley

MINE ADDRESS

Contact Name: Gary Harding, Mine Superintendent

Phone Number: 970-527-4135

Mailing Address: P.O. Box 1488

City: Paonia

State: CO

ZIP: 81428

GENERAL INFORMATION

Number of Employees at Mine: 53

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 13

Sulfur Content of Coal Produced: 0.39% - 0.50%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,400

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.1	0.8	0.4	0.6
Estimated Total Methane Liberated (million cf/day):	1.0	1.5	1.0	1.2
Emissions from Ventilation Systems:	1.0	1.5	1.0	1.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	328	729	902	723

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Bowie No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.08	0.12
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	5.5%	8.3%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.3%	1.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Delta-Montrose Elec. Assoc./Empire Elec. Assoc.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	4.5	18.2
Mine Electricity Demand:	3.5	14.5
Prep Plant Electricity Demand:	1.0	3.6
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.8	15.9
Assuming 60% Recovery Efficiency: ¹	2.7	23.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.3
Description of Surrounding Terrain:	Open Low Mountains/High Mountains
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Rocky Mountain Natural Gas
Distance to Pipeline (miles):	17.5
Pipeline Diameter (inches):	6.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Bowie No. 1 (continued)

Summary of Recent News

Bowie Resources Ltd. purchased the Bowie No. 1 mine, formerly the Orchard Valley mine, from Cyprus Amax Coal Co. in December 1994 (CW 1/2/95 p. 1, CO 1/30/95 pp. 1-2). Bowie Resources also obtained the shares of the mine that were owned by Mitsubishi Minerals and Samsung Corp. (CW 10/17/94 p. 7, CO 12/11/95 p. 6). Cyprus Amax had acquired the mine, along with a term contract with Northern Indiana Public Service Co. (NIPSCO), from Colorado Westmoreland Inc. (CW 10/17/94 p. 7, CO 1/30/95 pp. 1-2). Cyprus Amax idled operations at the Orchard Valley mine in October 1994, partly in response to the expiration of the contract with NIPSCO in June 1994, and declining prices in the Pacific Rim coal market, one of Orchard Valley's export markets (CO 7/4/94 p. 1, CW 10/17/94 p. 7, CO 12/19/94 pp. 1, 8).

Bowie No. 1 is located in Delta County, Colorado, and is operated by a contract miner, Bruin Mining Co. LLC (CO 7/17/95 p. 5). The mine is a room-and-pillar operation that produces coal averaging 11,312 Btu/lb. with a sulfur content of 0.48 percent and an ash content of 7.73 percent (Keystone 1997). The life expectancy of Bowie No. 1, which had been predicted to operate until about 2010, may be extended if the company chooses to acquire additional reserves from the Bureau of Land Management (BLM). In the fall of 1996, Bowie Resources applied to the BLM for a license to explore 1,958 acres (CO 10/14/96 p. 4).

In December 1996, the company reported that the mining operations at Bowie No. 1 had encountered "low coal" due to a split seam, but should be able to move beyond it to a new area with 11 million tons of reserves after four to five months. The new reserves are near old mining operations that closed following a fire in the 1980s; the company plans to steer clear of the old mine works to avoid any potential complications due to smoldering fires, flooding, and trapped carbon monoxide. A new contractor, Sherpa Paonia, will manage the mining of the low coal. The company does not expect this development to impact mine production or costs (CO 12/23/96 pp. 2-3).

In February 1995, Coors Brewing sold to Bowie Resources its Bowie reserve, which is contiguous to, but not accessible from, Bowie No. 1 (CO 1/30/95 pp. 1-2). In February 1996, Bowie Resources applied for a permit to open a new deep mine, Bowie No. 2, on the Bowie reserve. This mine's two continuous miners could produce about 2 million tons of coal per year, and could supplement and then replace production by Bowie No. 1 (CO 3/4/96 p. 3). Bowie No. 2 should start production in mid- to late 1997 (CO 9/30/97 p. 4, CO 12/23/96 pp. 2-3).

In February 1997, Mitsui Matsushima Co. Ltd., a Japanese coal-trading company, announced that its subsidiary, Mitsui Matsushima America Inc., planned to purchase a 22.5 percent share of Bowie Resources at a cost of \$5 million. Mitsui Matsushima will have exclusive control over anticipated coal exports of 500,000 to 1 million tons per year from the Bowie No. 2 mine to the Japanese market (CO 2/10/97 p. 9).

Sales & Supply

As part of the Bowie reserve purchase in 1995, Bowie Resources obtained a term contract to supply about 350,000 tons of coal per year to the Coors plant in Golden, Colorado. Bowie No. 1 will be the initial supplier of this coal (CO 1/30/95 pp. 1-2). This contract to supply the Coors plant remained in place following Coors' decision in the summer of 1995 to sell its coal- and gas-fired power and steam facilities, fuel tanks, and gas pipeline to a utility partnership composed of Nations Energy and Trigen Energy (CO 7/17/95 p. 5).

The Bowie No. 1 (Orchard Valley) mine has also supplied spot orders to the Tennessee Valley Authority (TVA), including orders for 230,000 tons in the third quarter of 1994, 180,000 tons in the first quarter of 1995, and an unspecified amount supplied from March through December 1996 (CW 1/23/95 p. 7, CW 10/16/95 p. 7, CW 6/3/96 p. 4). In May 1996, TVA announced that it would obtain 3.6 million tons of Requisition 33 coal from Bowie Resources over a six-year term (CO 5/13/96 p. 1, CO 5/20/96 p. 7, CO 9/30/96 p. 4).

Updated: May 1997

Status: Operating

Deserado

GEOGRAPHIC DATA

Basin: Western (Piceance)

State: CO

Coalbed: Basin D/C

County: Rio Blanco

CORPORATE INFORMATION

Current Owner: Western Fuels-Utah

Parent Company: Western Fuels

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Mike Weigand, Mine Manager

Phone Number: 970-675-8431

Mailing Address: P.O. Box 1067

City: Rangely

State: CO

ZIP: 81645

GENERAL INFORMATION

Number of Employees at Mine: 252

Mining Method: Longwall

Year of Initial Production: 1982

Primary Coal Use: Steam

Mine Life Expectancy (years): 36

Sulfur Content of Coal Produced: 0.43% - 0.53%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 10,704

Depth to Seam (ft): 1,850

Seam Thickness (ft): 8.0 - 9.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.5	1.5	1.0	0.5
Estimated Total Methane Liberated (million cf/day):	1.3	1.2	1.0	0.7
Emissions from Ventilation Systems:	0.8	0.7	0.6	0.4
Estimated Methane Drained:	0.5	0.5	0.4	0.3
Estimated Specific Emissions (cf/ton):	327	279	349	459

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob

Deserado (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.04	0.06
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.7%	5.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.9%	1.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Moon Lake Electric

Parent Corporation of Utility: Deseret Generation & Transmission Cooperative

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	4.0	15.9
Mine Electricity Demand:	3.1	12.7
Prep Plant Electricity Demand:	0.9	3.2
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.0	8.8
Assuming 60% Recovery Efficiency: ¹	1.5	13.3

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain:	Open Low Mountains
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Northwest Pipeline
Distance to Pipeline (miles):	NA
Pipeline Diameter (inches):	6.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Welding facilities; hospital, college, and municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Deserado (continued)

Summary of Recent News

Deserado mine is located in Rio Blanco County, Colorado. The mine opened in 1982 and subsequently installed a longwall in 1987, which now is responsible for 80% of its output (Coal 12/94 p.35). Western Fuels-Utah, co-owned by Western Fuels Association (WFA) (10%) and Deseret Generation & Transmission (90%), is the mine's owner and operator (CO 9/9/96 p.5). WFA is "a fuel supply cooperative comprised of consumer-owned electric utilities in the Great Plains, the Rocky Mountains, and the Southwest and Louisiana" (Coal 12/94 p.35).

The mine's D seam produces low-sulfur coal of around 0.45% (Coal 12/94 p.35) for one customer, the Deseret Generation & Transmission Association's Bonanza plant in Utah (CW 2/12/96 p.1). The mine is located 37 miles from Deseret and is connected to the plant by the Deseret Western Railroad (Coal 7/94). The mine normally employs 120 miners underground and 140 miners on the surface (Coal 12/94 p.35).

In the past few years, Deserado has attempted to overcome the limitations of its conveyor system and increase its output by, among other things, improving the system's hardware, employing a belt-splicing technique to decrease the chances of belt failure, and increasing the longwall's face widths (Coal 12/94 p.35).

In July 1995, the Deserado mine was idled while its owner, Deseret Generation & Transmission, underwent financial restructuring. Deseret converted its 400,000 ton stockpile of coal into cash, restructured mining operations, and switched to producing partially washed coal. The mine also added a shearing machine for mining thinner coal seams (Coal 12/95 p.5).

On January 31, 1996, a fire started in the Deserado mine when welders repairing the pan conveyor on the tailgate area of the longwall set off a methane excursion. The mine was evacuated, and none of the 70 workers at the mine were injured in the fire, but some cribbing was burned that triggered a roof fall. Several days later crews drilled holes into the mine to inject CO₂ and smother the fire, and to pump out methane (CW 2/12/96 p.1). By February 10, 1996, the CO₂ had failed to extinguish the fire, and the working area was sealed off along with the mine's longwall equipment and 4 years worth of coal reserves in the D seam. The company estimated the replacement cost of the equipment lost in the fire to be around \$32 million (CW 2/12/96).

Following the fire, WFA was determined to regain its position as Deseret Generation and Transmission's sole supplier and immediately ordered new longwall equipment and continuous miners for the D seam. The company planned to mine the Colorado B seam, with an estimated 40 years of reserves, once the D seam reserves were depleted. Until the Deserado mine resumed production, however, WFA decided to extend its truck hauling contracts, and it arranged for 120,000 tons of coal to be shipped to Deseret from other Colorado and Utah mines (CW 2/9/96 p.1). WFA extended a spot contract with Andalex Resources for coal from that company's Tower operation in Utah, for 60,000 tons per month, and purchased an additional 60,000 tons per month of coal from Kennecott Energy's Colowyo mine (CO 2/12/96 p.1).

By mid-April, the Deserado mine was back in operation with the installation of a new continuous miner unit (CO 4/15/96 p.4). By late September 1996, three continuous miners were once again operating in the Colorado D seam, producing at a rate of 1.3 million tons per year (CW 9/23/96 p.6). However, continuing roof problems lead WFA to purchase 150,000 tons of replacement spot coal that month from Kennecott Energy. In addition, there was speculation that WFA would sell its 10% share in Western Fuels-Utah to Deseret, as the latter might soon undergo additional financial restructuring (CO 9/9/96). Currently, WFA plans to install a new longwall by late 1997 (CW 9/23/96 p.6).

On April 29, 1996, the UMWA ratified a new 3-year contract for the Deserado mine. Under the agreement Deserado's miners won the rights to maintenance and repair work in the mine, and on the railway lines that connected Deserado to the Bonanza power plant. The workers also received a ratification bonus, amounting to around \$0.65 per hour.

Updated: May 1997

Status: Closed/Using

Golden Eagle

GEOGRAPHIC DATA

Basin: Western (Raton Mesa)

State: CO

Coalbed: Maxwell

County: Las Animas

CORPORATE INFORMATION

Current Owner: Basin Resources

Parent Company: Entech Coal (a subsidiary of Montana Power)

Previous Owner(s): KN Energy's Wyoming Fuel Co.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Paul Gatzemeier, President, Basin Resources

Phone Number: 719-868-2761

Mailing Address: 14300 Highway 12

City: Weston

State: CO

ZIP: 81091

GENERAL INFORMATION

Number of Employees at Mine: 225¹

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 0.41% - 0.46%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,100

Depth to Seam (ft): 600

Seam Thickness (ft): 8.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.9	1.1	1.2	0.0
Estimated Total Methane Liberated (million cf/day):	6.8	8.5	7.5	0.0
Emissions from Ventilation Systems:	4.1	5.1	4.5	0.0
Estimated Methane Drained:	2.7	3.4	3.0	0.0
Estimated Specific Emissions (cf/ton):	2,882	2,785	2,369	0

Estimated Current Drainage Efficiency: Mine closed

Drainage System Used: Re-entry of Vertical Gob, Pre-Mine and Utility Boreholes, Ventilation Shafts

¹ Number of employees based on when mine was in operation.

Golden Eagle (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.49	0.73
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	17.0%	25.5%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	3.9%	5.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: San Isabel Electric Services, Inc.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	8.7	34.7
Mine Electricity Demand:	6.7	27.7
Prep Plant Electricity Demand:	2.0	6.9
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency:	11.4	99.5
Assuming 60% Recovery Efficiency:	17.0	149.3

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf):	1.1
Assuming 60% Recovery Efficiency (Bcf):	1.6
Description of Surrounding Terrain:	Open Hills/Open High Hills
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Colorado Interstate Gas
Distance to Pipeline (miles):	23.3
	Pipeline Diameter (inches): 10.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Sawmills; hospitals, schools, and other municipal buildings.

Golden Eagle (continued)

Summary of Recent News

Golden Eagle is a longwall mine located in Colorado and owned by Basin Resources, a subsidiary of Entech. Entech's parent company, Montana Power, acquired Golden Eagle from KN Energy in 1991 (CW 1/15/96). The mine controls 200 million tons of reserves (CW 9/4/95). Due to geologic problems that hindered longwall operations, Golden Eagle suffered financial losses in 1994 and 1995, including a \$9.5 million loss during the first nine months of 1995. Because of these difficulties, Basin Resources closed Golden Eagle on December 29, 1995 (CO 1/8/96).

Golden Eagle's major customer was Tampa Electric Co., which held a 1.5 million ton per year contract for delivery of the mine's high-Btu, low-sulfur coal. The Tampa contract, signed in 1994, was for a 10 year period (CW 1/8/96). Tampa Electric Co. bought the balance of already mined coal, which equaled 110,000 tons when the mine closed in December 1995 (CW 2/12/96). Golden Eagle also supplied coal to APG Lime's New Braunfels plant.

While Golden Eagle produced more than 1 million tons per year, it had been running well below its 2 million ton a year capacity (CO 11/13/95). Before the decision to close down the mine was definite, Montana Power considered selling it. Parties that took a tour of the mine included CONSOL, Westmoreland Coal, and Kerr-McGee Coal (CO 12/11/95).

Since early 1997, Stroud Oil Properties Inc. has been producing methane from vertical boreholes that Basin Resources had drilled at the mine when it was still operating (Stroud, 1997).

Updated: May 1997

Status: Operating

Sanborn Creek

GEOGRAPHIC DATA

Basin: Western (Piceance)

State: CO

Coalbed: B Seam

County: Gunnison

CORPORATE INFORMATION

Current Owner: Pacific Basin Resources

Parent Company: Oxbow Carbon and Mineral Group

Previous Owner(s): Somerset Mining Company and Bear Coal

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Walter L. Wright, Mine Manager

Phone Number: 970-929-5122

Mailing Address: P.O. Box 535

City: Somerset

State: CO

ZIP: 81434

GENERAL INFORMATION

Number of Employees at Mine: 107

Mining Method: Room & Pillar

Year of Initial Production: 1991

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 19

Sulfur Content of Coal Produced: 0.47% - 0.62%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 12,240

Depth to Seam (ft): 1,000

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.8	1.1	1.1	1.2
Estimated Total Methane Liberated (million cf/day):	2.9	5.1	5.4	4.5
Emissions from Ventilation Systems:	2.9	5.1	5.4	4.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	1,262	1,763	1,862	1,419

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Sanborn Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.29	0.44
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	10.1%	15.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	2.3%	3.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Gunnison Light & Water Dept.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	6.7	27.8
Mine Electricity Demand:	6.7	27.8
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	6.8	59.7
Assuming 60% Recovery Efficiency: ¹	10.2	89.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.7
Assuming 60% Recovery Efficiency (Bcf): ¹	1.0
Description of Surrounding Terrain: Hilly/Mountainous	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Williams Field Services	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Hospital and other institutional facilities.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Sanborn Creek (continued)

Summary of Recent News

The Sanborn Creek mine is located in Gunnison County, Colorado. The mine produces soft coking coal and high quality steam coal with a heating content of 12,300-12,500 Btu/lb and a sulfur content of less than 0.5%. It mines the Colorado B coal seam with two continuous miners (CO 6/17/96 p.5; CW 7/17/95 p.1). Sanborn Creek's primary metallurgical coal customer is Geneva Steel, and it has long-term contracts with Wisconsin Electric Power and Illinois Power to supply steam coal (CW 7/17/95 p.2).

The Sanborn Creek mine, currently owned by Oxbow Carbon & Minerals, has been through a number of ownership shuffles in the past decade. Sanborn Creek and its previous operator, Somerset Mining, were jointly owned by Pacific Basin Resources (PBR) and Bear Coal, who bought the property in 1990 from bankrupt Kaiser Coal (CW 7/17/95 p.1). PBR and Bear Coal became involved in a legal dispute over operating issues in 1994 (CW 7/17/95 p.1), and as a result, the companies dissolved their partnership. In June 1995, PBR purchased Bear Coal's 35% interest in the company (CO 10/16/95 p.3), as well as a loadout in Somerset, Colorado (CW 7/17/95 p.1). The two companies still jointly ship coal out of Sanborn Creek and Bear Coal's No. 3 mine near Somerset, and PBR continues to market coal from the No. 3 mine (CW 7/17/95 p.1). Under the agreement, operation of the mine shifted to PBR and Somerset Mining has ceased to exist (CO 7/17/95 p.5). In October 1995, the Oxbow Group (PBR's parent company) combined PBR with Oxbow Carbon International to form Oxbow Carbon & Mineral Group (Oxbow), which now runs Sanborn Creek (CW 10/16/95 p.2).

Though the companies are no longer partners, the fortunes of Bear Coal continue to influence the fortunes of Oxbow Carbon & Minerals and its Sanborn Creek operation. In November 1996, Bear Coal closed its No. 3 mine, citing an impending end to economic coal reserves and a recent roof fall. Oxbow, which markets coal from both the No. 3 mine and its own Sanborn Creek operation, planned to respond by increasing production at Sanborn Creek to make up for the lost production from the No. 3 mine. A spokesman said that Oxbow may switch Sanborn Creek to a 7-day-per-week production schedule, up from its current two-shift-per-day, Monday through Friday operation (CO 12/9/96 p.3).

Demand for Sanborn Creek's product continues to be strong. In early 1995, PBR signed a three-year contract with Illinois Power to ship 350,000 tons of steam coal per year, as part of a deal with two other western coal producers, Coastal States Energies and ARCO Coal (CW 1/2/95 p.7). PBR also signed a short term contract with Wisconsin Electric Power Company (WEPCO) to supply steam coal to WEPCO's Presque Isle plant for the 1995 lake season, under a backhaul agreement with Southern Pacific Transportation (CW 5/8/95 p.7).

Production at the Sanborn Creek mine is currently limited because it is a room-and-pillar operation. However, in June 1996, Oxbow Carbon & Minerals hired Weir International to assess the feasibility of installing a longwall at the mine. An official with Oxbow said the mine may begin using a longwall, at the earliest, by 1998. However, even with a longwall the mine would still not produce as much as the neighboring West Elk mine, which works the same coal seam and is longwall-equipped. Sanborn Creek, with around 40 million tons of recoverable coal, has a smaller reserve base than West Elk (CO 6/17/96 p.5). Installation of a longwall is likely to increase production at Sanborn Creek to around 3.0 to 3.5 million tons per year and ease MSHA safety concerns over using the room-and-pillar method at such great depths. As of May 1997, the mine was moving forward with plans to begin using a longwall.

Updated: May 1997

Status: Operating

Southfield

GEOGRAPHIC DATA

Basin: Western (Canon City Field)

State: CO

Coalbed: Jack-o-Lantern & Red Arrow

County: Fremont

CORPORATE INFORMATION

Current Owner: Energy Fuels Coal, Inc.

Parent Company: Energy Fuels Coal, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: James Cooper, V.P. Coal Operations

Phone Number: 303-623-8317

Mailing Address: 1200 17th Street, Suite 2500

City: Denver

State: CO

ZIP: 80202

GENERAL INFORMATION

Number of Employees at Mine: 77

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.62% - 0.74%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 11,100

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.3	0.3	0.3	0.2
Estimated Total Methane Liberated (million cf/day):	0.7	0.6	0.6	0.4
Emissions from Ventilation Systems:	0.7	0.6	0.6	0.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	842	706	725	859

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Southfield (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.03	0.04
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	6.7%	10.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.5%	2.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Westplains Energy

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	1.0	4.1
Mine Electricity Demand:	1.0	4.1
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.6	5.3
Assuming 60% Recovery Efficiency: ¹	0.9	8.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Colorado Interstate Gas	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): 20.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Southfield (continued)

Summary of Recent News

The Southfield mine is a room-and-pillar operation located in Fremont County, Colorado, producing steam coal with a sulfur content of approximately 0.60% (1997 Keystone Coal Industry Manual). It is owned and operated by Energy Fuels Coal Inc. Southfield's 1994 production totaled 310,321 tons, but the mine is capable of producing up to 700,000 tons of coal per year (CO 10/3/94 p.2). The mine employs 77 workers.

In 1996, there was speculation that Energy Fuels would close the Southfield mine. However, in June 1996, the company announced that the mine would be kept open as a result of a new contract with a local cement company. Southfield will produce around 200,000 tons per year for three years under the new contract (CO 6/17/96 p.4).

Updated: May 1997

Status: Operating

West Elk

GEOGRAPHIC DATA

Basin: Western (Piceance)

State: CO

Coalbed: B Seam

County: Gunnison

CORPORATE INFORMATION

Current Owner: Mountain Coal

Parent Company: Atlantic Richfield/ITOCHU Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: Mt. Gunnison

MINE ADDRESS

Contact Name: Gene Diccaudio, President

Phone Number: 303-929-5015

Mailing Address: P.O. Box 591

City: Somerset

State: CO

ZIP: 80202

GENERAL INFORMATION

Number of Employees at Mine: 190

Mining Method: Longwall

Year of Initial Production: 1982

Primary Coal Use: Steam

Mine Life Expectancy (years): 23

Sulfur Content of Coal Produced: 0.46%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 11,800

Depth to Seam (ft): 1,000

Seam Thickness (ft): 14.0 - 23.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	3.0	4.2	5.3	5.9
Estimated Total Methane Liberated (million cf/day):	2.0	2.6	2.1	4.1
Emissions from Ventilation Systems:	2.0	2.6	2.1	4.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	243	223	144	252

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

West Elk (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.27	0.40
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.9%	2.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Delta Montrose Elec. Assoc./Gunnison County Elec. Assoc.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	34.5	142.8
Mine Electricity Demand:	34.5	142.8
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	6.2	54.4
Assuming 60% Recovery Efficiency: ¹	9.3	81.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.6
Assuming 60% Recovery Efficiency (Bcf): ¹	0.9
Description of Surrounding Terrain: Hilly/Mountainous	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: KN Energy	
Distance to Pipeline (miles): 10.0	Pipeline Diameter (inches): 4.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Hospital and other institutional facilities.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

West Elk (continued)

Summary of Recent News

West Elk is owned by ARCO Coal and operated by its Mountain Coal unit. West Elk opened in 1982¹ as a continuous miner operation on the Western slope of Colorado near Somerset. After commissioning its longwall mining system in July 1992, the mine experienced a dramatic increase in production from 1.4 million tons in 1992 to 5.3 million tons in 1995.

In April 1996, West Elk set a new world production record for a single longwall operation. West Elk produced 781,355 clean tons of coal in a month. The previous record was 689,759 tons, set by Cyprus Amax Coal's Twentymile mine (CW 6/3/96). Twentymile answered the challenge by breaking West Elk's record a couple of months later. For 1996, West Elk produced in excess of 5.5 million tons of high Btu, low-sulfur coal for domestic and international markets (CW 6/3/96). ARCO has high hopes of eventually increasing production at West Elk to 10 million tons while still remaining a single longwall operation (CO 5/15/95). In 1995, ARCO requested and was granted a mine permit revision from the Colorado Department of Natural Resources which gave West Elk permission to operate at a production rate of 8.2 million tons per year (CO 10/30/95).

Furthermore, in 1996, ARCO made the necessary capital expenditures to allow West Elk to enter new reserves (CW 2/5/96). West Elk operates under a Bureau of Land Management (BLM) license which allows it to explore reserves for potential lease. West Elk's management is interested in some deep reserves. In 1995, West Elk leased 37 million tons of coal from the BLM (CO 11/27/95).

In trying to finish out the latest panel, West Elk has been struggling to mine through a parting. A parting is a stratum typically less than one foot thick composed of "dull" coal, which is a coal that is more gray than black due to impurities. The parting grades from dull coal to carbonaceous shale and occasional sandstone (CO 12/16/96). West Elk did not foresee the trouble because during initial core drilling on this part of the reserve the two nearest bore holes missed the parting by about 200 feet each.

Extensive core drilling reveals that the parting extends for 30 to 40 miles but affects only one more panel. If the company keeps to the current schedule, it is due to hit the parting again in late March or early April 1997. Working through the parting will slow mining for approximately three months. However, West Elk may simply forego this area of the reserve and set up a panel elsewhere (CO 12/16/96). West Elk is considering seeking royalty rate reductions which are sometimes granted by the federal government for major geologic disruptions, such as partings or faults, occurring in federal coal reserves. The standard royalty is 8% of the gross value of the coal. However, the royalty can also be as low as 5% for severe geologic problems (CO 12/16/96).

Sales & Supply

In December 1994, West Elk filled a spot order of 150,000 tons to Tennessee Valley Authority's Colbert steam plant, units 1-4 (CO 5/15/95).

In 1995, West Elk supplied Illinois Power's Wood River and Havana plants with 350,000 tons of coal (CO 7/24/95).

Union Electric (UE) purchases about 1 million tons per year of West Elk coal under a long-term contract that runs through 2001. UE then aggressively markets its West Elk coal to other end users and will burn Powder River Basin (PRB) coal itself. In 1995, UE sold 200,000 tons to Nevada Power and 250,000 tons to Nevada Power's Reid Gardner plant (CO 12/4/95). In addition, a Drummond Co. affiliate has a deal with UE to market a portion of UE's West Elk tonnage in 1996 and 1997. As part of the deal, UE will have the opportunity to replace any coal the Drummond Co. affiliate sells with its own PRB coal (CO 6/17/96).

¹ At that time it was called the Mt. Gunnison mine.

West Elk (continued)

The Colorado coal market made gains in 1996 and the beginning of 1997 at the expense of Central Appalachia coal. The Tennessee Valley Authority announced in May 1996 its decision to use Colorado coal over Appalachian for its Colbert and Widows Creek plants (CO 5/13/96). TVA awarded three Colorado contracts totaling 6.6 million tons -- two to ARCO for West Elk coal and one to Bowie Resources. ARCO and Bowie together will supply up to 1.7 million tons per year to Colbert, and ARCO will supply up to 600,000 tons per year for Widows Creek (CO 5/20/96).

In 1996, WEPCO tested West Elk coal at its Port Washington and Valley plants as an option for compliance with Phase 2 of the 1990 Clean Air Act (6/17/96). The test burns were successful at Port Washington. WEPCO will burn a 50/50 blend of West Elk and the plant's normal coal from the Bailey mine through the end of 1997. Deliveries from West Elk to Port Washington for 1996 were 100,000 tons, and will be 200,000 tons for 1997. At the Valley plant, 25% West Elk coal and 75% Bailey coal was the optimal blend. However, the blend is not economic, so the plant will continue to use 100% Bailey through 1997 (CO 9/16/96). WEPCO is also testing Illinois Basin coal in blends with Colorado coal from West Elk (CO 9/30/96).

Powderhorn's Roadside deep mine was idled in December 1996. The West Elk mine is the likely candidate to substitute Powderhorn's coal supply to Interstate Power, amounting to 450,000 tons per year until 1998 (CO 10/14/96).

6. Profiled Mines (continued)

Illinois Mines

Brushy Creek
Crown II
Elkhart
Galatia No. 56
Monterey No. 1
Monterey No. 2
Old Ben No. 24
Old Ben No. 25
Old Ben No. 26
Orient No. 6
Pattiki
Rend Lake
Wabash

Updated: May 1997

Status: Operating

Brushy Creek

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Saline

CORPORATE INFORMATION

Current Owner: Western Fuels-Illinois/Brushy Creek Coal Co.

Parent Company: Western Fuels

Previous Owner(s): Kenellis Energies, Inc.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Paul Smock, Underground Superintendent

Phone Number: 618-252-8633

Mailing Address: 4270 North America Rd.

City: Galatia

State: IL

ZIP: 62935

GENERAL INFORMATION

Number of Employees at Mine: 120

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 3

Sulfur Content of Coal Produced: 2.70% - 2.80%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,550

Depth to Seam (ft): 250

Seam Thickness (ft): 5.8

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.3	1.3	0.5	0.6
Estimated Total Methane Liberated (million cf/day):	1.0	0.7	0.5	0.8
Emissions from Ventilation Systems:	1.0	0.7	0.5	0.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	274	193	360	506

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Brushy Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.05	0.08
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.9%	5.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.9%	1.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	4.3	17.3
Mine Electricity Demand:	3.3	13.8
Prep Plant Electricity Demand:	1.0	3.5
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.2	10.6
Assuming 60% Recovery Efficiency: ¹	1.8	15.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Open Hills/Irregular Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Texas Eastern Transmission	
Distance to Pipeline (miles): 1.7	Pipeline Diameter (inches): 24.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Apparel, fertilizers, trusses, and mine equipment manufacturing.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Brushy Creek (continued)

Summary of Recent News

Brushy Creek is a room-and-pillar mine located in Saline County, Illinois. The mine was purchased by Western Fuels Association (WFA) from Kenellis Energy in 1991. WFA is a fuel supply cooperative serving municipal utilities and electric power cooperatives west of the Mississippi river (CW 8/28/95 p.3).

The mine cannot support a longwall operation due to what a WFA official described as geologic problems created by prior oil and gas drilling on the property (CO 7/24/95 p.2). The mine produces mostly medium-sulfur coal from its No. 6 coal seam, and has some lower-sulfur reserves in its No. 5 seam. Brushy Creek produced 1,322,958 tons of coal in 1994, 900,000 tons of which were sold on the spot market (CW 8/28/95 p.4). Brushy Creek's primary customers are the Kansas City, KS Board of Public Utilities, the Sikeston, MO Board of Municipal Utilities, Tennessee Valley Authority (TVA), Northern Indiana Public Service Company (NIPSCO) and Wisconsin Public Service. Contracts with Sikeston and Kansas City expire at the end of 1997 (CO 6/24/96 p.4).

Brushy Creek has been deeply impacted by poor market conditions, and sales of its high-sulfur coal have been affected by the Clean Air Act's limits on SO₂. In January 1995, Brushy Creek laid off 8 miners (CO 1/16/95 p.6), and in June 1995, WFA idled the Brushy Creek mine completely, thereby affecting 250 miners (Coal 7/95 p.9). At the time of the idling, Brushy Creek had a surplus of 300,000 tons of coal, expected to last 3 months (CW 3/20/95 p.1). A month later WFA issued WARN notices to Brushy Creek's employees, and informed workers that much of the mine would be closed by October 1995 (CO 8/7/95 p.2). WFA had planned to reopen the mine in Fall 1995 at production levels sufficient to meet the needs of its two primary customers, Kansas City and Sikeston, but at lower production than before the mine's closing (CO 9/11/95 p.4).

In November 1995, 60 miners were called back after union workers approved changes in work rules sought by the company. Brushy Creek's furloughed miners agreed to accept the national wage agreement between the UMWA and Bituminous Coal Operators Association, after having previously worked under an agreement between the union and WFA (CW 11/13/95 p.9). As of September 1996, Brushy Creek was operating at a production rate of 500 to 600 thousand tons per year (CO 6/24/96 p.4).

In June 1996, WFA began talks with various parties about a possible joint venture, in which a partner would take over the mine's operation and market excess production (CO 6/24/96 p.4). Possible interested parties include municipal utilities in Sikeston and Kansas City, both of which have coal contracts with Brushy Creek (CO 9/2/96 p.7). In December 1996, however, WFA began soliciting bids for alternatives to coal that Brushy Creek currently supplies to Sikeston, in what would be a 700,000 ton per year contract to start in December 1997 (CO 12/16/96 p.5).

Sales & Supply

As mentioned previously, Brushy Creek's primary customers are the Kansas City, KS Board of Public Utilities, the Sikeston, MO Board of Municipal Utilities, TVA, NIPSCO and Wisconsin Public Service (CO 6/24/96 p.4).

Updated: May 1997

Status: Operating

Crown II

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Macoupin

CORPORATE INFORMATION

Current Owner: Freeman United Coal Mining Co.

Parent Company: General Dynamics Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Tom Kell, Mine Superintendent

Phone Number: 217-698-3300

Mailing Address: P.O. Box 337

City: Virden

State: IL

ZIP: 62690

GENERAL INFORMATION

Number of Employees at Mine: 234

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 3.40%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 10,750

Depth to Seam (ft): NA

Seam Thickness (ft): 8.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.6	1.6	1.6	1.7
Estimated Total Methane Liberated (million cf/day):	0.6	0.5	0.6	0.7
Emissions from Ventilation Systems:	0.6	0.5	0.6	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	137	111	138	148

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Crown II (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.05	0.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.2%	1.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	13.0	51.9
Mine Electricity Demand:	10.0	41.5
Prep Plant Electricity Demand:	2.9	10.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.1	9.3
Assuming 60% Recovery Efficiency: ¹	1.6	13.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: NA	
Owner of Nearest Pipeline: United Cities Gas Co.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Crown II (continued)

Summary of Recent News

Crown No. 2 and its neighboring mine, Crown No. 3, are room-and-pillar mines located in Macoupin County, Illinois (CW 1/8/96 p.4). The Crown mines are owned by Freeman United Coal Company, a subsidiary of General Dynamics Corp. (CO 3/4/96 p.2). Freeman operates a total of four mines in Illinois (Orient No. 6, Crown No. 2 and No. 3, and Industry) and has 500 million tons of recoverable coal reserves (CO 9/2/96 p.1).

Both Crown No. 2 and No. 3 have remained open despite shut-downs at both the Industry and Orient No. 6 mines during the past few years (CO 2/26/96 p.7). The mine employs 234 workers, and all of Freeman United's miners are represented by the United Mine Workers of America (CO 2/26/96 p.7).

Sales & Supply

In its May-June 1994 transactions, TVA purchased 55,000 tons of 3.60% sulfur, 10,600 Btu/ton coal from Crown No. 2, at a price of \$21.23 per ton (delivered) (CW 9/19/94 p.8).

Eastern Illinois University exercised a one-year supply contract extension with Freeman in June of 1995 for coal from the Crown No. 2 mine (CW 6/26/95 p.6).

In February 1996, IES Utilities purchased 50,000 tons of spot coal from the Crown No. 2 mine (CW 3/4/96 p.6). Later that year, Freeman United signed a contract with Commonwealth Edison to supply 350,000 tons of coal from the Crown No. 2 and No. 3 mines, as part of a larger agreement with five producers for over 13 million tons of coal over the next three years. Other suppliers will include ARCO Coal's Black Thunder mine, Kerr-McGee Coal's Jacobs Ranch mine, and Freeman United Coal's Industry mine (CW 11/18/96 p.6).

Updated: May 1997

Status: Operating

Elkhart

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Springfield No. 5

County: Logan

CORPORATE INFORMATION

Current Owner: Turris Coal Co.

Parent Company: Zeigler Coal Holding Company

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Roger Dennison, President

Phone Number: 217-947-2951

Mailing Address: Elkhart Mine Rd., P.O. Box 21

City: Elkhart

State: IL

ZIP: 62634

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 3.00% - 3.20%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 10,454

Depth to Seam (ft): NA

Seam Thickness (ft): 5.6

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.5	1.7	1.7	2.0
Estimated Total Methane Liberated (million cf/day):	0.4	0.5	0.4	0.3
Emissions from Ventilation Systems:	0.4	0.5	0.4	0.3
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	97	109	84	55

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Elkhart (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

Assumed Potential Recovery Efficiency¹

(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.02	0.03
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.5%	0.7%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Light Company

Parent Corporation of Utility: Cilcorp, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	14.9	59.5
Mine Electricity Demand:	11.5	47.6
Prep Plant Electricity Demand:	3.4	11.9
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.5	4.0
Assuming 60% Recovery Efficiency: ¹	0.7	6.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.0
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain:	Irregular Plains
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Central Illinois Light Company
Distance to Pipeline (miles):	NA
Pipeline Diameter (inches):	NA
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant:	NA
Distance to Plant (miles):	NA
Boiler Capacity (MW):	NA
Nearby Industrial/Institutional Facilities?:	Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Elkhart (continued)

Summary of Recent News

Sales & Supply

In June 1995, the State of Illinois renewed Elkhart's contract for 14,400 tons of 3.8% sulfur, 10,650 Btu/lb., at a price of \$27.97 per ton (delivered). The coal is for the Jacksonville Developmental Center (CW 6/19/95 p.7). In June 1996, the contract with the State of Illinois was again renewed at a price of \$29.15 per ton (CW 6/3/96 p.5).

There is no further information available for this mine.

Updated: May 1997

Status: Operating

Galatia No. 56

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6/Harrisburg No. 5

County: Saline

CORPORATE INFORMATION

Current Owner: Kerr-McGee Coal Corp.

Parent Company: Kerr-McGee Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: S.S. Rowland, General Manager

Phone Number: 618-268-6311

Mailing Address: P.O. Box 727

City: Harrisburg

State: IL

ZIP: 62946

GENERAL INFORMATION

Number of Employees at Mine: 580

Mining Method: Longwall

Year of Initial Production: 1983

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.70% - 2.80%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,000

Depth to Seam (ft): 700

Seam Thickness (ft): 7.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	4.2	4.0	5.5	6.5
Estimated Total Methane Liberated (million cf/day):	4.5	7.3	8.4	8.9
Emissions from Ventilation Systems:	4.5	7.3	8.4	8.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	395	663	556	498

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Galatia No. 56 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.58	0.87
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.7%	5.5%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.8%	1.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	48.9	195.6
Mine Electricity Demand:	37.8	156.5
Prep Plant Electricity Demand:	11.1	39.1
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	13.5	118.1
Assuming 60% Recovery Efficiency: ¹	20.2	177.2

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.3
Assuming 60% Recovery Efficiency (Bcf): ¹	1.9
Description of Surrounding Terrain: Open Hills/Irregular Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Texas Eastern Transmission	
Distance to Pipeline (miles): 0.8	Pipeline Diameter (inches): 24.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Apparel, fertilizers, trusses, and mine equipment manufacturing.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Galatia No. 56 (continued)

Summary of Recent News

Galatia No. 56 (Galatia), located in Illinois, is a large, deep mine that produces medium-sulfur coal. Over the past couple of years, Kerr-McGee has expanded its facility at the Galatia mine and greatly increased production. In 1996, production hit a record 6.6 million tons per year and is expected to be of a similar magnitude in 1997 (CO 1/27/97). Galatia sustained two closures and still was extremely successful in the market, producing at peak capacity and having buyers for all of its coal.

Kerr-McGee made many changes that improved the coal operations at Galatia. In 1994, Galatia switched all operations out of the high-sulfur No. 6 seam to the medium-sulfur No. 5 seam (CO 10/30/95). Presently, Galatia has two longwalls in the No. 5 seam. Kerr-McGee also commissioned a major expansion of the preparation plant, which increased the shipping capacity to over 6 million tons per year. Production increased from 4.5 million tons per year in 1994 to 5.5 million tons per year in 1995 and to 6.6 million tons per year in 1996. To accommodate the increased production, Kerr-McGee is exploring new markets for the coal. In 1995, Galatia exported 27-29 percent of its coal to a number of international customers (CW 7/17/95).

The rail-to-port movement from Galatia to the Port of Mobile, Alabama is a major factor in Galatia's success. Galatia exports coal to Japan, Europe, and North Africa. The Galatia expansion has posed a challenge to the transportation infrastructure which had no prior experience with the volumes now produced at Galatia (CW 7/17/95). In March 1996, Illinois Central Railroad, the primary shipper of Galatia coal, announced plans for a major bulk materials port on the Mississippi River near Baton Rouge. The new terminal's objective is not to diverge the already substantial domestic business transported through Mobile, but rather serve expanding export and domestic opportunities, which could play a role for Galatia. The new facility's rail access, for both loading and unloading, will set it apart from other Mississippi coal ports (CW 3/25/96).

Two brief shut-downs are the only blemishes on Galatia's successful record. On October 17, 1996, the Mine Safety and Health Administration discovered a fire in a closed section of the mine during monitoring (CW 10/21/96). MSHA issued an imminent danger order which halted mining operations for about a week. Kerr-McGee sealed the fire area and pumped in carbon dioxide through two 500-foot-deep bore holes drilled above the fire. However, this attempt failed. The fire eventually burned out, but the area remains sealed and constantly monitored (CW 10/28/96). On October 23, 1996, Galatia resumed full production when MSHA lifted the imminent danger order, allowing Galatia's approximately 600 miners to return to work. Galatia had enough coal on hand to continue making deliveries during the brief shutdown (CW 10/28/96).

The mine experienced another evacuation on January 15, 1997. MSHA halted production for approximately three hours due to a high methane reading at a borehole, near the area where hot spots idled operations back in October 1996 (CO 1/27/97). Kerr-McGee expects to move one of the longwalls about two miles from where it is now operating, but still remaining in the No. 5 seam. The longwall was scheduled to be operational by mid-February 1997 (CO 1/27/97).

Sales & Supply

For the last quarter of 1994 and the first quarter of 1995, Galatia delivered higher-sulfur coal to Wansley of Southern Co. (CO 2/13/95). Also, Georgia received about 500,000 tons of Galatia coal under a six-month contract that expired in March 1995 (CO 4/10/95).

From January 1, 1995 through December 31, 1998, Galatia supplied Mississippi Power Co. with 1 million tons per year of 12,000 Btu/lb. and 1.2 percent sulfur coal for the Jack Watson power plant on the Mississippi River. Based on Galatia coal's specifications, 1 million tons per year contains 12,000 tons per year of sulfur, so its SO₂ emissions would be about 24,000 tons per year, which is well under Watson's Phase I limit. The Galatia coal cost \$20.50 per ton FOB barge (CW 1/8/96).

In 1996, Kerr-McGee decided to sell less Galatia coal overseas. It maintained shipments of steam coal to Germany. It served two German contracts, Preussen Elektra and Stinnes, a coal trading firm (CO

Galatia No. 56 (continued)

2/19/96). However, it did not even bid for Moroccan ONE because all the increased output was already sold. Galatia has supplied ONE for several years and shipped roughly 550,000 tons to Morocco in 1995 (CO 2/5/96).

Beginning in 1996 and running for two years, Galatia will supply 40,000 tons per year coal to Wolverine Power Supply Cooperative Inc. The agreement allows Wolverine to increase the tonnage by 20,000 tons per year, or reduce the tonnage by 10,000 tons per year (CW 2/26/96). Also in 1996, Galatia supplied Tampa at Big Bend (CO 1/15/96).

In September 1996, the Tennessee Valley Authority selected seven coal-producing companies to supply up to 39.2 million tons of coal over the next six years to four TVA power plants -- Allen, Gallatin, Johnsonville, and Shawnee. The seven companies include: Kerr-McGee, Arch Mineral, Costain, Genwal, Sugar Camp, Thunder Basin, and Twentymile Coal. Kerr-McGee will ship about 3,900 tons per week of Galatia coal to Johnsonville. The targeted starting date for delivery was January 1, 1997 (CW 9/9/96). In October 1996, Wisconsin Electric Power Co. began a test burn of Kerr-McGee's Galatia mine coal at its Port Washington Plant. The 20,000-ton test burn could lead to Kerr-McGee supplying half of the tonnage for a 1-5 year term coal solicitation issued in March by Wisconsin Electric (CW 10/7/96).

Recently, a partial buyout occurred on a long-term contract which involves Galatia. Peabody COALSALES has a 12 1/2 year contract with Gulf Power under which COALSALES supplies 1.9 million tons per year of a blend of 900,000 tons of Galatia coal and 1 million tons of Guasare, Venezuelan coal. However, on December 28, 1995, the two parties agreed to a partial buyout of their contract. Under the agreement, Gulf Power paid \$22 million to buy out delivery of the Guasare products from January 1, 1996 through January 31, 1998 (CW 3/11/96). Gulf said the Venezuelan coal had become too expensive and that it would replace it with a lower-cost domestic coal that would not have to be blended with the Galatia coal. The Galatia coal will continue its supply under its part of the COALSALES contract (CW 3/4/96). In 1996, COALSALES supplied Gulf Power's Smith power plant near Pensacola with 20,000 tons per month of Galatia coal in October, November, and December (CW 10/7/96).

Updated: May 1997

Status: Operating

Monterey No. 1

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Macoupin

CORPORATE INFORMATION

Current Owner: Monterey Coal

Parent Company: Exxon Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: John Lanecrotte, Production Superintendent

Phone Number: 217-854-3291

Mailing Address: P.O. Box 496

City: Carlinville

State: IL

ZIP: 62626

GENERAL INFORMATION

Number of Employees at Mine: 325

Mining Method: Longwall

Year of Initial Production: 1977

Primary Coal Use: Steam

Mine Life Expectancy (years): 13

Sulfur Content of Coal Produced: 1.00% - 3.60%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 10,600

Depth to Seam (ft): 300

Seam Thickness (ft): 5.8 - 7.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	2.1	2.1	2.4
Estimated Total Methane Liberated (million cf/day):	0.7	0.9	0.7	0.5
Emissions from Ventilation Systems:	0.7	0.9	0.7	0.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	150	153	122	75

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Monterey No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.03	0.05
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.6%	0.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Illinois Power Co.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	18.2	72.9
Mine Electricity Demand:	14.1	58.3
Prep Plant Electricity Demand:	4.1	14.6
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.8	6.6
Assuming 60% Recovery Efficiency: ¹	1.1	10.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain: Irregular/Smooth Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Illinois Power	
Distance to Pipeline (miles): 1.7	Pipeline Diameter (inches): 4.0
Owner of Next Nearest Pipeline: Panhandle Eastern Pipeline	
Distance to Next Nearest Pipeline (miles): 26.7	Pipeline Diameter (inches): 26.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Central Illinois Public Service Coffeen Plant

Distance to Plant (miles): 35.0 Boiler Capacity (MW): 913.0

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Monterey No. 1 (continued)

Summary of Recent News

Exxon Coal's subsidiary, Monterey Coal, owns both the Monterey No. 1 and No. 2 mines located in Illinois. Monterey No. 1 is 20 years old and produces a 1%-sulfur coal mainly for a long-term contract with Central Illinois Public Service (CIPS). The low-sulfur coal is compliant with Phase I of the 1990 Clean Air Act. Exxon installed a longwall at the mine for the first time in April 1994 in order to fulfill the contract with CIPS.

Presently, Monterey No. 1 is Exxon's only operating coal mine in the U.S. Exxon shut down its No. 2 mine on July 19, 1996, after its main contract was bought out by Public Service of Indiana. Exxon states that it will continue to operate No. 1, though, and has no plans to sell the mine (CO 8/5/96). In fact, Exxon is upgrading the coal prep plant so output will rise from 2.6 million to 3 million tons per year as Exxon secures new sales contracts (CO 7/15/96). However, there is speculation by some that the mine is or soon will be up for sale. Zeigler Coal Holding is one of the interested parties (CO 8/5/96).

Sales & Supply

Monterey No. 1 is under contract to supply a minimum of 1.7 million tons per year of coal to Central Illinois Public Service's Coffeen plant. That coal is for compliance with Phase I of the 1990 Clean Air Act, which began January 1, 1995 (CO 1/23/95).

Updated: May 1997

Status: Idle

Monterey No. 2

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Clinton

CORPORATE INFORMATION

Current Owner: Monterey Coal

Parent Company: Exxon Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Linda Krupnik, Production Superintendent

Phone Number: 618-248-5121

Mailing Address: P.O. Box 94

City: Albers

State: IL

ZIP: 62215

GENERAL INFORMATION

Number of Employees at Mine: 407¹

Mining Method: Room & Pillar

Year of Initial Production: 1977

Primary Coal Use: Steam

Mine Life Expectancy (years): 5

Sulfur Content of Coal Produced: 3.30% - 3.54%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 10,845

Depth to Seam (ft): 330

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.1	3.0	3.0	1.7
Estimated Total Methane Liberated (million cf/day):	0.2	0.3	0.5	0.4
Emissions from Ventilation Systems:	0.2	0.3	0.5	0.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	69	36	58	88

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

¹ Number of employees based on when mine was in operation.

Monterey No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.03	0.04
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.7%	1.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.2%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Illinois Power Co.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	9.9	40.8
Mine Electricity Demand:	9.9	40.8
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ²	0.6	5.5
Assuming 60% Recovery Efficiency: ²	0.9	8.2

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.1
Assuming 60% Recovery Efficiency (Bcf): ²	0.1
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Illinois Power	
Distance to Pipeline (miles): 3.3	Pipeline Diameter (inches): 4.0
Owner of Next Nearest Pipeline: NGPL	
Distance to Next Nearest Pipeline (miles): 18.3	Pipeline Diameter (inches): 30.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Monterey No. 2 (continued)

Summary of Recent News

Monterey No. 2 (as well as Monterey No. 1) is owned by Monterey Coal, a subsidiary of Exxon. Monterey No. 2 was developed in 1977 to supply Public Service of Indiana's Gibson Generating Station near Princeton, Indiana. Monterey No. 2 had a long-term contract with PSI that begun in 1977 and was due to expire December 2002. However, early in 1996, PSI terminated the remaining 5 1/2 years of the mine's 3 million tons per year high-sulfur coal supply contract. This termination caused the Monterey No. 2 mine to close down in July 1996.

PSI began negotiations with Exxon in 1991 over a 5-year contract reopener and then filed suit in May 1992, saying it would terminate the contract if Exxon failed to match a lower offer from Black Beauty (CO 5/18/92). The U.S. Supreme Court ultimately ruled in favor of Exxon. PSI felt the case was handled unfairly when the Supreme Court declined to review decisions by an appeals court on a lower court ruling (CO 8/8/94). The lower court ruling set the price of the coal at \$30.00 per ton instead of the \$23.26 per ton PSI offer. PSI had been paying approximately \$38.00 per ton before it summoned the contract reopener provision in 1991 (CW 9/5/94).

PSI's dissatisfaction with the Supreme Court decision lead to its buyout of the Exxon contract in mid-1996. The delivered price of the Monterey coal earlier in 1996 was approximately \$31.25 per ton, compared to the average spot price of \$24.94 per ton (CO 7/15/96). PSI Energy announced in August 1996 it had agreed to purchase as much as 3.3 million tons per year of coal from Black Beauty over 10 years. This replaced the PSI pact with Monterey No. 2 (CW 9/16/96). PSI estimates its ratepayers would save up to \$80 million over the 10-year period under the Black Beauty deal. As part of the agreement, PSI was to pay a buyout fee of \$151,105,662 plus interest of \$27,952,938 (CW 9/16/96).

All of the mine's production had been dedicated to the PSI/Gibson contract. After the PSI buyout, Exxon was determined to put closure and reclamation of No. 2 on a fast track. Exxon stated that it would entertain any reasonable offer for the sale of the 19-year-old mine (CW 7/22/96). However, the UMW was frustrated with Exxon, claiming they simply ignored interested parties. The mine has worked up to the edge of a medium-sulfur reserve that could easily be tapped from the existing mine works. However, there is an economic concern over the medium-sulfur reserves having an unstable roof (CO 8/5/96).

Exxon conducted studies of the high-sulfur Illinois Basin coal market and concluded that extensive operational changes and improvements would be necessary at No. 2 in order to be even somewhat competitive (CO 7/15/96). The Monterey No. 2 high-sulfur coal (3.4 percent) and relatively low heating content (~ 10,800 Btu/lb) make its quality inferior to some other Illinois basin operations. On July 19, 1996, the mine ceased operations. Exxon gave workers a 60-day WARN layoff notice on July 3, 1996 (CO 8/5/96). Some 330 hourly and 65 salaried workers lost their jobs (CO 7/15/96).

Exxon finally did put Monterey No. 2 up for sale. Recently, the UMW has tried to work out a partial buy for the mine through an employee stock ownership plan. The UMW wants to buy 40% of the mine, with Freeman United Coal also purchasing 40%, and a private investor out of St. Louis providing the final 20% (CO 1/6/97). Freeman is refusing to give the union a role in the operation of the mine after the purchase, and this is stifling the negotiations on the ownership structure (CO 2/10/97). In late-February 1997, Freeman United Coal dropped out as a possible partner with the UMW. The UMW was talking with two other companies about the possibilities of a joint-venture buy of the mine. One of those companies was Indiana producer, Phoenix Natural Resources, but the company is no longer interested (CO 3/3/97; CO 5/5/97). There is still no word from the other party.

Updated: May 1997

Status: Closed

Old Ben No. 24

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Franklin

CORPORATE INFORMATION

Current Owner: Old Ben Coal Co.

Parent Company: Zeigler Coal Holding Company

Previous Owner(s): British Petroleum (previous parent co.)

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: David M. Young, President, Old Ben Coal

Phone Number: 618-435-8176

Mailing Address: RR #3, Mine 24

City: Benton

State: IL

ZIP: 62812

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Longwall

Year of Initial Production: 1966

Primary Coal Use: Steam

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 2.20% - 2.59%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,700

Depth to Seam (ft): 650

Seam Thickness (ft): 7.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.8	2.1	2.3	0.5
Estimated Total Methane Liberated (million cf/day):	1.0	1.5	1.3	1.2
Emissions from Ventilation Systems:	1.0	1.5	1.3	1.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	439	264	204	878

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Old Ben No. 24 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.08	0.12
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	6.6%	9.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.5%	2.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	3.7	15.0
Mine Electricity Demand:	2.9	12.0
Prep Plant Electricity Demand:	0.9	3.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ²	1.8	15.9
Assuming 60% Recovery Efficiency: ²	2.7	23.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.2
Assuming 60% Recovery Efficiency (Bcf): ²	0.3
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: C.I.P.S. Gas Transmission	
Distance to Pipeline (miles): 1.7	Pipeline Diameter (inches): 6.0
Owner of Next Nearest Pipeline: Trunkline Gas	
Distance to Next Nearest Pipeline (miles): 12.5	Pipeline Diameter (inches): 36.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Old Ben No. 24 (continued)

Summary of Recent News

Old Ben No. 24 is a deep, high-sulfur coal mine located in Illinois. Ziegler purchased No. 24 and three other Old Ben Coal mines in 1990 from British Petroleum. The No. 24 mine contains 20 to 25 years of coal. However, the mine closed down in March 1996 due to a lack of demand for high-sulfur coal (CO 4/8/96).

During the last couple years of operation, No. 24 had a few set backs in production. In early 1995, the mine was operating at a capacity of 725 tons per hour despite the mine's prep plant's inability to process coal at that rate (CO 3/20/95). As a result, No. 24 had to reduce production going to a five-day-a-week production schedule. Additionally, during Summer 1995 the mine temporarily closed due to a faulty longwall motor (CO 3/20/95).

Sales & Supply

Both Old Ben No. 24 and No. 26 frequently shipped coal under the same contract. One of those contracts, which was with the Tennessee Valley Authority, expired at the end of 1996. The other contract, which was with Springfield City Utilities, expired in March 1997 (CO 6/12/95). Despite the contract terms, when coal production ceased at Old Ben No. 24, in March 1996, deliveries of Old Ben No. 24 coal to these utilities also stopped.

Updated: May 1997

Status: Closed

Old Ben No. 25

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Franklin

CORPORATE INFORMATION

Current Owner: Old Ben Coal Co.

Parent Company: Zeigler Coal Holding Company

Previous Owner(s): British Petroleum (previous parent co.)

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: David M. Young, President, Old Ben Coal

Phone Number: 618-435-8176

Mailing Address: P.O. Box 637

City: West Frankfort

State: IL

ZIP: 62896

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Longwall

Year of Initial Production: 1977

Primary Coal Use: Steam

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 2.00% - 2.70%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 11,700

Depth to Seam (ft): 600

Seam Thickness (ft): 7.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.6	1.5	0.0	0.0
Estimated Total Methane Liberated (million cf/day):	1.4	1.0	0.0	0.0
Emissions from Ventilation Systems:	1.4	1.0	0.0	0.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	313	247	0	0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Old Ben No. 25 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1994 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.10
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.9%	2.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1994 data):	8.6	35.4
Mine Electricity Demand:	8.6	35.4
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1994 data)		
Assuming 40% Recovery Efficiency: ²	1.5	13.3
Assuming 60% Recovery Efficiency: ²	2.3	19.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1994 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.1
Assuming 60% Recovery Efficiency (Bcf): ²	0.2
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Trunkline Gas	
Distance to Pipeline (miles): 4.2	Pipeline Diameter (inches): 36.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Old Ben No. 25 (continued)

Summary of Recent News

Zeigler's Old Ben No. 25 is one of four Old Ben coal mines in Illinois. No. 25 closed in Fall 1994. The mine reopened as the National Museum of Coal Mining on June 11, 1996. Travelers/Aetna Property Casualty issued the reclamation bond needed to restore the mine and surrounding buildings. The museum is expected to attract 20,000 visitors in the first year of operation (CO 6/10/96). Before its closing in 1994, Old Ben No. 25 produced approximately 1.5 million tons of coal (CO 8/1/94).

Updated: May 1997

Status: Closed

Old Ben No. 26

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Franklin

CORPORATE INFORMATION

Current Owner: Old Ben Coal Co.

Parent Company: Zeigler Coal Holding Company

Previous Owner(s): British Petroleum (previous parent co.)

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: David M. Young, President, Old Ben Coal

Phone Number: 618-435-8176

Mailing Address: RR #1, Box 759

City: Sesser

State: IL

ZIP: 62884

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Longwall

Year of Initial Production: 1969

Primary Coal Use: Steam

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 2.20%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,650

Depth to Seam (ft): 650

Seam Thickness (ft): 8.5 - 9.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.6	3.1	3.0	3.1
Estimated Total Methane Liberated (million cf/day):	2.0	2.1	1.7	1.6
Emissions from Ventilation Systems:	2.0	2.1	1.7	1.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	452	251	209	186

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Old Ben No. 26 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.10	0.16
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.4%	2.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	23.5	94.1
Mine Electricity Demand:	18.2	75.3
Prep Plant Electricity Demand:	5.3	18.8
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ²	2.4	21.2
Assuming 60% Recovery Efficiency: ²	3.6	31.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.2
Assuming 60% Recovery Efficiency (Bcf): ²	0.4
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: C.I.P.S. Gas Transmission	
Distance to Pipeline (miles): 3.3	Pipeline Diameter (inches): 4.0
Owner of Next Nearest Pipeline: Trunkline Gas	
Distance to Next Nearest Pipeline (miles): 13.3	Pipeline Diameter (inches): 36.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Old Ben No. 26 (continued)

Summary of Recent News

In 1990, Ziegler acquired Old Ben No. 26, along with three other Old Ben Coal mines in Illinois, from British Petroleum. Old Ben No. 26 closed on December 31, 1996, after operating for 28 years. The mine was due to close in the fall of 1996 but its life was extended because there was extra coal that could be mined (CO 4/22/96). The mine closed as a result of the depletion of reserves and a lack of market for high-sulfur coal. Just hours after its closing a fire broke out on the coal conveyor belt. In response to the fire Ziegler decided to seal the mine's shaft, meaning that No. 26 will probably never produce coal again. Sealing of the mine was completed on January 8, 1997. At the time the fire broke out, an unspecified amount of equipment still remained hundreds of feet underground. Zeigler had planned to keep about 30 miners for several weeks to recover the equipment. However, the fire forced their early dismissal (Coal Age 2/97).

Sales & Supply

Both Old Ben No. 26 and No. 24 shipped coal under a contract with the Tennessee Valley Authority that expired at the end of 1996. The mines also supplied a term contract with Springfield City Utilities that expired in March 1997 (CO 6/12/95).

Updated: May 1997

Status: Operating

Orient No. 6

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Jefferson

CORPORATE INFORMATION

Current Owner: Freeman United Coal Mining Co.

Parent Company: General Dynamics Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Jim Hess, Mine Superintendent

Phone Number: 217-698-3300

Mailing Address: P.O. Box 308

City: Waltonville

State: IL

ZIP: 62894

GENERAL INFORMATION

Number of Employees at Mine: 180

Mining Method: Longwall

Year of Initial Production: 1976

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.65%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,800

Depth to Seam (ft): 800

Seam Thickness (ft): 5.5 - 6.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.3	1.4	1.4	1.1
Estimated Total Methane Liberated (million cf/day):	0.8	0.7	0.8	0.7
Emissions from Ventilation Systems:	0.8	0.7	0.8	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	229	179	203	230

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Orient No. 6 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.05	0.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.7%	2.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	8.3	33.4
Mine Electricity Demand:	6.4	26.7
Prep Plant Electricity Demand:	1.9	6.7
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.1	9.3
Assuming 60% Recovery Efficiency: ¹	1.6	13.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Central Illinois Light Company	
Distance to Pipeline (miles): 1.3	Pipeline Diameter (inches): 3.0
Owner of Next Nearest Pipeline: NGPL	
Distance to Next Nearest Pipeline (miles): 15.0	Pipeline Diameter (inches): 30.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Tires, apparel, plaster, boat manufacturing and mining supplies; hospital.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Orient No. 6 (continued)

Summary of Recent News

The Orient No. 6 mine is a longwall operation located in Jefferson County, Illinois. Orient No. 6 is owned by Freeman United Coal Company, a subsidiary of General Dynamics Corp. (CO 3/4/96 p.2). Freeman operates a total of four mines in Illinois (Orient No. 6, Crown No. 2 and No. 3, and Industry) and has 500 million tons of recoverable coal reserves (CO 9/2/96 p.1). Workers at Orient No. 6 are represented by the United Mine Workers of America (CO 2/26/96 p.7).

Orient No. 6 has been impacted by rising costs and the Clean Air Act's restrictions on sulfur emissions. In December 1995, Freeman issued WARN notices to all of Orient's employees, and in February 1996 Freeman cut back production at the mine, laying off 119 employees as a result. Most of the affected employees were doing longwall development work (CO 3/4/96 p.2).

One acknowledged problem at the Orient No. 6 mine is that its coal has had a high rejection rate (more than 50%). The reject rate has resulted from problems with establishing the correct angle and direction of the longwall panels. When the angle and direction are not set correctly, the longwall cuts into the overlying strata, and unwanted coal and rock cuttings are included with the desired high quality coal. Freeman had planned to move the longwall to a new panel, hopefully cutting the reject rate, but the company may close the mine if the new plan fails to cut costs (CO 3/4/96 p.2). The Orient mine was planning to produce around 1 million tons of coal in 1996, down from 1.4 million tons in the year ending June 30, 1995 (CO 2/26/96 p.7).

Sales & Supply

In its October-December 1994 transactions, TVA purchased 100,000 tons of 2.05% sulfur coal from Orient No. 6, at a price of \$26.79 (FOB plant) (CW 5/15/95 p.7). In January-March 1995, TVA purchased 40,000 tons of 11,750 Btu/lb., 1.8% sulfur coal from Orient No. 6, at a price of \$26.48 per ton. TVA also bought 300,000 tons of 11,700 Btu/lb., 1.8% sulfur coal for \$25.03 per ton (CW 10/16/95 p.7).

The State of Illinois announced in June 1995 that it would renew all of its coal supply contracts, including one with Orient No. 6 for 7,600 tons of 11,100 Btu/lb., 3.3% sulfur coal, at a price of \$33.78 per ton, delivered (CW 6/19/95 p.7).

In December 1995, PSI Energy purchased 20,000 tons per month from Orient No. 6 for the period January through March 1996. Orient No. 6, as well as CONSOL's Rend Lake mine, Costain's Baker mine, and Maple Creek's mine in Washington County, PA, all agreed to supply coal to PSI's Gallagher power plant for the first few months of 1996. PSI is testing new coals at the plant in an effort to expand Gallagher's portfolio of available coals (CO 12/18/95 p.7).

Updated: May 1997

Status: Operating

Pattiki

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: White

CORPORATE INFORMATION

Current Owner: White County Coal Corp.

Parent Company: MAPCO Coal, Inc. (Beacon Energy Investment Fund)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Bob Johnson, Mine Superintendent

Phone Number: 618-382-4651

Mailing Address: R.R. #1, P.O. Box 457

City: Carmi

State: IL

ZIP: 62821

GENERAL INFORMATION

Number of Employees at Mine: 236

Mining Method: Room & Pillar

Year of Initial Production: 1985

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 2.50% - 2.87%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,766

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.0	2.0	1.8	1.8
Estimated Total Methane Liberated (million cf/day):	1.3	1.3	2.2	1.7
Emissions from Ventilation Systems:	1.3	1.3	2.2	1.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	238	240	444	345

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pattiki (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.11	0.17
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.6%	3.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.6%	0.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Carmi Water & Light Dept.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	13.5	53.9
Mine Electricity Demand:	10.4	43.1
Prep Plant Electricity Demand:	3.1	10.8
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	2.6	22.6
Assuming 60% Recovery Efficiency: ¹	3.9	33.8

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.4
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Texas Eastern Transmission	
Distance to Pipeline (miles): 3.3	Pipeline Diameter (inches): 24.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Pattiki (continued)

Summary of Recent News

MAPCO Coal's Pattiki mine, located in southern Illinois, has recently experienced changes in stock ownership and management. On June 28, 1996, the Beacon Group Energy Investment Fund acquired the stock of MAPCO Coal and MC Mining for \$250 million through a stock purchase agreement with MAPCO Inc. (CW 11/18/96).

Pattiki was one of several mines transferred with MAPCO Coal's stock; the others were Dotiki in western Kentucky, Martiki and Pontiki in eastern Kentucky, Mettiki in Maryland, and Permac and Racefork in Virginia. MAPCO assured Beacon Group at the time of final closing that none of its employees were unionized and that there were no strikes, slowdowns, or court filings pending against the MAPCO Coal companies (CW 11/18/96).

As part of the sale, MAPCO Inc. signed a non-competition agreement that prevents MAPCO Inc. and its subsidiaries and affiliates from producing, importing, selling, or distributing coal anywhere in the world (except Indonesia) for a period of two years after the sale date (CW 11/18/96). MAPCO Coal's key customers include Seminole Electric, Virginia Power, Duke Power, Cogentrix, Tennessee Valley Authority, CINERGY, US Steel, and Delmarva Power.

In September 1995, MAPCO Coal Co. appointed Jim Plaisted sales manager for the central region. He covers the Tennessee Valley Authority and the river markets with a focus on the Pattiki and Dotiki mines (CW 9/25/95). Mr. Plaisted joined MAPCO from Koch Carbon and previously worked for TVA as fuels purchaser.

Back in November 1991, Pattiki sustained an underground mine fire that forced an evacuation and temporary closure of the mine. The blaze was apparently caused by a gob that ignited spontaneously. It was located in an area that was not being mined and no injuries were reported (CW 11/11/91).

Sales & Supply

Currently, Pattiki supplies Seminole Electric (Seminole) with 1.1 million tons per year (CW 4/22/96). Under two different contracts which expired at the end of 1995, Pattiki had previously supplied Seminole with 78,000 tons of coal at \$48.11 per ton and 51,000 tons of coal at \$38.06 per ton (CO 10/31/94).

In June 1995, Gulf Power Co. began receiving spot coal from Pattiki under a purchase order issued November 1994. The FPSC reports for July 1995 stated Pattiki's coal price as \$21.05 per ton FOB barge (CW 10/16/95). From March to June 1996, the mine supplied 3.3 lb. SO₂/mmBtu coal to Gallatin (CW 6/3/96).

In June 1995, MAPCO Coal offered Grand Haven (MI) Board of Light & Power a bid for Pattiki FOB mine at 79 cents/mmBtu (CW 6/5/95).

In October 1994, MAPCO Coal offered Big Rivers Electric Corp. 1,440,000 tons (40,000 tons per month) of Pattiki coal for \$23.60 per ton, \$24.19 per ton, and \$24.79 per ton (CW 10/31/94).

Updated: May 1997

Status: Operating

Rend Lake

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: Jefferson

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): Inland Steel

Previous or Alternate Name of Mine: Inland No. 1

MINE ADDRESS

Contact Name: Joseph J. Wetzel, Superintendent

Phone Number: 618-625-2041

Mailing Address: Route 148 N. of Sesser

City: Sesser

State: IL

ZIP: 62884

GENERAL INFORMATION

Number of Employees at Mine: 486

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.81% - 1.81%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,000

Depth to Seam (ft): 600

Seam Thickness (ft): 7.0 - 9.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.4	2.7	3.3	3.2
Estimated Total Methane Liberated (million cf/day):	1.2	1.2	2.2	2.2
Emissions from Ventilation Systems:	1.2	1.2	2.2	2.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	312	162	246	252

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Rend Lake (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.14	0.21
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.9%	2.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	23.9	95.6
Mine Electricity Demand:	18.5	76.5
Prep Plant Electricity Demand:	5.4	19.1
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	3.3	29.2
Assuming 60% Recovery Efficiency: ¹	5.0	43.8

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.3
Assuming 60% Recovery Efficiency (Bcf): ¹	0.5
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: C.I.P.S. Gas Transmission	
Distance to Pipeline (miles): 2.5	Pipeline Diameter (inches): 6.0
Owner of Next Nearest Pipeline: NGPL	
Distance to Next Nearest Pipeline (miles): 18.3	Pipeline Diameter (inches): 30.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Tires, apparel, plaster, boat manufacturing and mining supplies; hospital.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Rend Lake (continued)

Summary of Recent News

Rend Lake is located in Jefferson County, Illinois. The mine is owned by Consolidation Coal Company, a wholly owned subsidiary of the CONSOL Coal Group. Historically, the Rend Lake mine produced a medium-sulfur coal, but reports filed with the Federal Energy Regulatory Commission in early 1996 show that deliveries of Rend Lake coal contained only about 0.7 % sulfur. Rend Lake's low-sulfur coal is being accessed through a new portal the company installed in the Nason Point area (CW 4/29/96).

The newly tapped low-sulfur coal, coupled with newly discovered markets for Rend Lake coal, reinvigorated production at the mine and assuaged fears that Rend Lake would suffer the same fate as other Illinois coal producers, who were either closing or laying-off workers as a result of reduced production prompted by new clean air regulations (CO 3/4/96). In December 1995, CONSOL had furloughed about 97 miners, or about 20 percent of the total work force at its Rend Lake mine, citing market conditions as the reason for the layoffs (CW 1/8/96). By March 1996, though, with new coal contracts in place and a ready market for its product, Consolidation Coal Co. recalled 76 of the 97 employees it had laid off in December 1995. CONSOL did not divulge who the new coal buyers were, saying only that the call-back was a result of improved market conditions (CW 3/25/96). Industry watchers, however, speculated that the new agreements were with a utility in Indiana and the Southern Illinois Electric Cooperative. Further, industry watchers estimated that collectively the two utilities would buy more than 1 million tons annually (CW 3/25/96).

All of this activity happened just one year after Rend Lake hired aggressively to replace miners who took early retirement. Industry-wide there had been extensive hiring by coal companies looking to replace workers who had retired in Fall 1994 so as to ensure that they maintained their retiree health benefits under the Rockefeller provision of the 1992 Energy Policy Act. In Illinois, where Rend Lake is located, about 300 miners opted for early retirement. One of the largest contingencies retiring were those at Rend Lake. As a result of the call-backs, there had been rumors of production increases at Rend Lake, but the call-backs were to replace retiring miners and very little extra production resulted from the new hires (CO 12/21/94).

On August 26, 1996, CONSOL resumed production at the Rend Lake mine following a four-day shutdown. On August 21, 1996, an initial evacuation of about one-third of the mine's workers occurred when unusually high levels of carbon monoxide were detected underground. Federal and state inspectors were called in. Crews pinpointed hot spots in a gob pile in an abandoned section of the mine as the problem. To correct the problem, workers built seals at the entries to the abandoned area in order to isolate that area from oxygen that was helping to feed the hot-spots. As a result, production was suspended on August 22, 1996. After the operating portion passed the test for tolerable carbon monoxide levels, production resumed (CO 9/2/96).

Sales & Supply

Rend Lake's customers include Dairyland Electric Power Cooperative (Dairyland), Gulf Power, and Alabama Power (CW12/19/94; CW 4/29/96; CW 4/8/96).

In 1996, Dairyland reached agreement with CONSOL to purchase 600,000 - 700,000 tons of supplemental coal. In 1995, Dairyland bought 750,000 - 800,000 tons of supplemental coal (CW 2/12/96).

Also in 1995, Alabama Power placed orders for 50,000 tons of Rend Lake coal (CW 11/13/95).

In late 1996, PSI Energy selected Rend Lake coal for test burns. The utility indicated that it would buy initial test quantities in the 15,000 per ton lots in the fourth quarter and follow-up test tonnage of up to 50,000 tons per month during the first half of 1996 (CW 12/11/96).

Updated: May 1997

Status: Operating

Wabash

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Springfield No. 5

County: Wabash

CORPORATE INFORMATION

Current Owner: Amax Coal Co.

Parent Company: Cyprus Amax

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Bert Hall, General Mine Manager

Phone Number: 618-298-2394

Mailing Address: P.O. Box 144

City: Keensburg

State: IL

ZIP: 62852

GENERAL INFORMATION

Number of Employees at Mine: 380

Mining Method: Room & Pillar

Year of Initial Production: 1973

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.35% - 1.62%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 10,600

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	3.4	2.7	2.6	3.2
Estimated Total Methane Liberated (million cf/day):	2.9	4.5	5.8	4.7
Emissions from Ventilation Systems:	2.9	4.5	5.8	4.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	308	614	828	530

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Wabash (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.30	0.46
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	4.4%	6.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.0%	1.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Wayne White Counties Elec. Coop./Norris Elec. Coop.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	24.3	97.2
Mine Electricity Demand:	18.8	77.7
Prep Plant Electricity Demand:	5.5	19.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	7.1	62.4
Assuming 60% Recovery Efficiency: ¹	10.7	93.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.7
Assuming 60% Recovery Efficiency (Bcf): ¹	1.0
Description of Surrounding Terrain: Irregular Plains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Texas Eastern Transmission	
Distance to Pipeline (miles): 4.2	Pipeline Diameter (inches): 24.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Wabash (continued)

Summary of Recent News

The Wabash mine, located near Keensburg, Illinois, along the border between Illinois and Indiana, is owned by Cyprus Amax Coal Co., a Cyprus Amax Minerals Co. subsidiary that has become the second largest coal producer in the United States (Keystone 1997). As of December 1996, the Wabash mine, which began operations in 1973, was the country's largest underground mining operation that did not use a longwall (Coal 12/96 p. 45). The mine produces coal that averages 10,987 Btu/lb. with a sulfur content of 1.50 percent and an ash content of 10.61 percent (Keystone 1997).

The Wabash mine was developed to provide coal to PSI Energy's Gibson Generating Station in Princeton, Indiana (Coal 12/96 p. 45). The mine held a contract with PSI Energy to deliver 3.6 million tons of coal per year through 2002 (CO 4/27/92, CO 7/17/95 pp. 3-4). However, the Clean Air Act Amendments affected the Gibson plant's ability to burn high-sulfur coal without installing a scrubber. As a result, in August 1992, PSI Energy declared a force majeure on its contract with the mine (CW 8/31/92). The mine subsequently reduced production 30 percent, laid off 290 miners, and entered into legal proceedings against PSI Energy (CO 8/31/92, CO 2/14/94).

To remain competitive in the declining market for Midwest coal, the Wabash mine increased the efficiency of its operations, changing from twelve to seven production units that used a total of six continuous miners and operated three eight-hour shifts with crew changes at the face (Coal 12/96 pp. 45-46). The Wabash preparation plant, which the company upgraded and expanded in 1992 at a cost of \$20 million, produces washed coal at half the cost per ton of the national average (Coal 10/92, Coal 12/96 p. 48). In May 1995, the company reported that over the previous 12- to 16-month period, productivity at the Wabash mine increased from 18,000 to 23,000 raw tons per day (CO 5/22/95 p. 4). Also in May 1995, in an effort to further reduce operating costs, the Wabash mine eliminated 36 union and 15 salaried positions, the first personnel cutbacks in several years. At that time, about 640 union and salaried employees remained at the mine (CW 6/5/95 pp. 1-2, CO 6/12/95 p. 5).

In August 1995, Cyprus Amax and PSI Energy renegotiated their contract. Under the new contract, the Wabash mine was to continue to supply coal at the same tonnage to the Gibson plant, but at a price that would decline until it reached market levels by 1999. The price is to be adjusted annually starting in 2000, and the contract may be extended until 2010 (CW 7/17/95 pp. 1-2, CO 7/17/95 pp. 3-4, CO 8/28/95 p. 3, CO 2/10/97 pp. 1, 8). As a result of the contract renegotiation, the company wrote down the assets of the Wabash mine by \$310 million (pre-tax) in 1995 and implemented a new mine plan to reduce operating costs and increase reserves (CO 8/28/95 p. 3, CW 9/4/95 pp. 1-2). The mine acquired 50 million tons of additional reserves in 1995 (Coal 12/96 p. 48).

Although current mining operations are on the southern fringe of the reserves, the new reserves acquired by the mine in 1995 are located to the west. The mine planned to shift its mining operations into these reserves, and installed a new air shaft in preparation for the shift (CW 10/16/96, pp. 1-2, Coal 12/96 p. 46). The mine also planned to upgrade its main conveyor belt (Coal 12/96 p. 48).

Following the contract renegotiation, the company evaluated whether it should install a longwall mining system in order to boost the mine's productivity (CO 9/4/95 p. 6). However, local subsidence, oil wells in the reserves, and soft floor conditions posed potential barriers to installation of a longwall (Coal 12/96 p. 48). In addition, the company expressed concern regarding whether the market prices established under the PSI Energy contract would be sufficient to support the investment in the new longwall. The company also suggested that cooperation by union workers in reducing costs would also be a significant factor (CO 10/9/95 p. 6). In mid-1995, the company initiated the permitting process for longwall development at the Wabash mine (CO 2/5/96 p. 3). At the beginning of 1996, the mine laid off 75 miners (CW 1/8/96 p. 8). In July 1996, the company initiated the Labor/Management Positive Change Process, part of the agreement between the Bituminous Coal Operators' Association and UMWA, at the Wabash mine in order to further reduce operating costs (CO 7/15/96 p. 11).

In January 1997, Cyprus Amax reported that it was no longer considering a new longwall installation at the Wabash mine (CO 1/27/97, p. 9). In February 1997, Cyprus Amax announced that it had agreed to assign its contract with PSI Energy, the principal customer of the Wabash mine, to Black Beauty Coal in

Wabash (continued)

exchange for cash and future payments. Although Cyprus Amax reported that the agreement would not affect the company's 1997 earnings due to the cash payments, the agreement has placed the future of the Wabash mine into serious question. The mine issued 60-day WARN notices to 500 union and 111 salaried employees in February 1997 (CO 2/10/97 pp. 1,8). In March 1997, the company reported that the mine may continue to produce coal for the spot market, but that part of the mine would be closed and sealed (CO 3/10/97, pp. 1-2). On April 3, 1997, Cyprus Amax Coal laid off 469 workers. The mine will continue to supply coal to PSI's Gibson Power Plant, through May 1997, under an interim coal supply contract (CO 4/14/97).

6. Profiled Mines (continued)

Indiana Mines

Buck Creek

Updated: May 1997

Status: Idle

Buck Creek

GEOGRAPHIC DATA

Basin: Illinois

State: IN

Coalbed: Springfield No. 5

County: Sullivan

CORPORATE INFORMATION

Current Owner: Orion Resource Energie

Parent Company: Orion Diversified Technologies

Previous Owner(s): Buck Creek Coal, Inc.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Tommy Sutton, Mine Superintendent

Phone Number: 812-268-3371

Mailing Address: R.R. 5 Box 203

City: Sullivan

State: IN

ZIP: 47882

GENERAL INFORMATION

Number of Employees at Mine: 95 ¹

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.47% - 0.66%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 10,808

Depth to Seam (ft): 300

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.6	0.7	0.3	0.0
Estimated Total Methane Liberated (million cf/day):	0.4	0.5	0.4	0.3
Emissions from Ventilation Systems:	0.4	0.5	0.4	0.3
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	236	278	512	0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

¹ Number of employees based on when mine was in operation.

Buck Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.03	0.04
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	4.2%	6.3%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.9%	1.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: PSI Energy, Inc.

Parent Corporation of Utility: PSI Resources Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	2.1	8.5
Mine Electricity Demand:	1.7	6.8
Prep Plant Electricity Demand:	0.5	1.7
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ²	0.6	5.3
Assuming 60% Recovery Efficiency: ²	0.9	8.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.1
Assuming 60% Recovery Efficiency (Bcf): ²	0.1
Description of Surrounding Terrain: Waiting on New Data	
Transmission Pipeline in County?: NA	
Owner of Nearest Pipeline: Ohio Valley Gas Corp.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Buck Creek (continued)

Summary of Recent News

Buck Creek is a room-and-pillar mine located in Sullivan, Indiana. It is the largest underground mine in Indiana and produces metallurgical and steam coal with an average sulfur content of 0.58% (Coal 3/96 p.6). The Buck Creek mine was formerly operated by Buck Creek Coal Co., which is headquartered in Evansville, IN and is owned by Charles Shulties (CW 4/22/96 p.4). Peabody Coal owned the mine's reserves (CO 12/23/96 p.5).

In 1992, the United Mine Workers of America began an organizing drive at the Buck Creek mine (Coal 3/96 p.6). The union negotiated its first contract with Buck Creek for 15 months before launching a strike on March 31, 1993 (CW 11/7/94 p.3). The parties finally reached an agreement ending the strike in November 1994 (Coal 3/96 p.6). The final agreement included safety provisions, stipulations for wages and hours, and improved health care and pension benefits (CW 11/7/94).

Buck Creek is only six miles from Hoosier Energy, one of its primary customers. The mine's other customers have included Central Illinois Public Service (CIPS) and Inland Steel (CO 12/18/95 p.5). In December 1994, Hoosier Energy announced that it would not be renewing its term coal contract with Buck Creek Coal. Hoosier Energy had been receiving around half of Buck Creek's production (CO 2/6/96 p.6). As a result, Buck Creek was forced to idle the mine on December 16, 1994 (CO 2/6/95 p.6).

In February 1995, half of Buck Creek's employees returned to work in the mine's north unit (CO 2/6/95 p.6). The mine resumed producing coal selling most of the product to CIPS and selling some surplus production to Inland Steel (6/26/96 p.5). In November 1995, Buck Creek laid off 31 miners as a result of a contract dispute with CIPS (CO 11/6/95 p.3). CIPS had argued that its contract expired on December 31, 1995, while Buck Creek had thought that the agreement was tonnage-based (CO 11/6/95 p.8). Having already lost the Hoosier Energy contract, Buck Creek went to court to try to preserve its remaining contract with CIPS (Coal 3/96 p.6). By the end of 1995 the company's only remaining contract was with Inland Steel (CO 12/18/95 p.5). The Buck Creek mine was idled again in December 1995, as a result of losing the Hoosier Energy contract renewal and the expiration of the CIPS contract (12/18/95 p.5).

Buck Creek declared Chapter 7 involuntary bankruptcy in February 1996 after four of its creditors, Royal Brass & Hose, Titan Steel Products, Anker Hydraulic, and Lebco Inc., filed a liquidation petition against the company in the U.S. District Court in Indianapolis, IN (CO 2/12/96, p.1). Sources at the UMW said that Buck Creek also owed the union for unpaid health benefits and back wages (CO 2/12/96 p.1). The company later converted to a Chapter 11 bankruptcy, under which it could reorganize its debt (Coal 3/96, p.6). During the bankruptcy proceedings Buck Creek Coal changed its name to Indiana Coal Co., (CO 6/24/96 p.4) and the company continued to ventilate the mine to keep it ready to resume production (CW 9/9/96 p.2).

Shortly after its declaration of bankruptcy, Buck Creek Coal Company was put up for sale, generating interest from several potential buyers (CW 4/22/96 p.4). Most of its mining equipment was sold. In early June 1996, officials of the company pleaded guilty to a number of charges related to a federal investigation, including conspiracy, safety violations, and lying to federal investigators (CO 6/17/96 p.3). Because the company was bankrupt at the time (mid-1996), it probably avoided large fines associated with these charges (CO 6/17/96 p.4). By December 1996, Buck Creek was nearing completion of a deal in which the company would be purchased by Orion Diversified Technologies (Orion). Orion is a publicly traded investment company in Ronkonkoma, NY, and has no other holdings in the coal business (CW 9/9/96 p.1).

The agreement was to be a "stock-for-asset" swap in which Orion would get most of the company's equipment and assets in exchange for 500,000 shares of stock in Orion (CW 9/9/96 p.1). The mine would be operated by Orion Resource Energie and would be managed by local coal operator Rick Risinger (CO 12/23/96 p.5). Peabody Coal had planned to transfer the leases on the reserves to the new owners when the sale was completed (CO 12/23/96 p.5). As of late December 1996, the only remaining obstacle to the sale was an outstanding violation on the slurry ponds at the mine's prep plant (CO

Buck Creek (continued)

12/23/96 p.4). Orion had hoped to resume mining as soon as possible, as it already had two customers for Buck Creek's coal amounting to 60 to 80 thousand tons per month (CO 12/23/96).

However, Orion Diversified Technologies was unable to close the deal by December 31, 1996, the deadline set by the bankruptcy judge. Currently, two unidentified parties are negotiating to buy the assets of Buck Creek Coal. Orion is not one of them. It is not expected that Orion will resume negotiations to purchase Buck Creek Coal unless it improves its financial offer. Since December 31, 1996, prices for Illinois Basin coal has increased, thereby inflating the purchase price for Buck Creek Coal (CO 4/7/97).

6. Profiled Mines (continued)

Kentucky Mines

Arch No. 37
Baker
Camp No. 11
Clean Energy No. 1
Dotiki
Freedom Energy No. 1
Pontiki No. 1
Pontiki No. 2
Wheatcroft No. 9
Wolf Creek No. 4

Updated: May 1997

Status: Operating

Arch No. 37

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Alma

County: Harlan

CORPORATE INFORMATION

Current Owner: Arch of Kentucky, Division of Apogee Coal

Parent Company: Arch Mineral Corp. (Ashland Oil/Hunt)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: Lynch No. 37

MINE ADDRESS

Contact Name: Ken McCoy, Mine Manager

Phone Number: 606-589-2986

Mailing Address: P.O. Box 787

City: Lynch

State: KY

ZIP: 40855

GENERAL INFORMATION

Number of Employees at Mine: 285

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 1

Sulfur Content of Coal Produced: 0.66% - 1.87%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 1,700

Seam Thickness (ft): 8.0 - 10.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	3.9	3.9	4.5
Estimated Total Methane Liberated (million cf/day):	0.6	0.8	1.1	1.0
Emissions from Ventilation Systems:	0.6	0.8	1.1	1.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	131	74	102	77

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Arch No. 37 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.09
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.5%	0.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	26.4	109.1
Mine Electricity Demand:	26.4	109.1
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.5	12.7
Assuming 60% Recovery Efficiency: ¹	2.2	19.1

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain:	High Hills/Low Mountains
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Kentucky-W.Va. Gas
Distance to Pipeline (miles):	18.0
Pipeline Diameter (inches):	10.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Arch No. 37 (continued)

Summary of Recent News

Arch Mineral's No. 37 mine is a longwall mine located in Kentucky. Arch bought No. 37 from U.S. Steel in the mid-1980's. Currently, Arch No. 37 is facing a reduction in output, changes in management, and a possible merger.

Arch Mineral expects to exhaust the remaining coal that is extractable via longwall at No. 37 during the third quarter of 1997. Arch has mines in the planning stages that should be able to replace some of the coal normally supplied by No. 37 (CO 1/20/97).

In June 1996, Arch Mineral appointed Charles Russell as the new president of Arch of Kentucky, which operates the No. 37 longwall mine in Harlan County. He replaced Mike Zervos. Zervos left to go work for Drummond Coal, taking several supervisory-level people with him in the process (CO 6/17/96).

Ashland Inc. is actively pursuing a merger of Ashland Coal and Arch Mineral. Ashland Inc. holds 56% of the stock of Ashland Coal and 50% of Arch (the other 50% of Arch is held by the Hunt family in Texas). The two companies have yet to decide what the ownership structure would be if the coal producers merge. Earlier attempts to merge failed because the parties were unable to agree on the value of each company. Both companies have experienced profit troubles in recent years, therefore cost reduction is an extra incentive to combine. Arch's profitability has been improving though. For fiscal year 1996, Ashland Inc. reported \$13 million in equity income from its 50% share of Arch (an improvement from the \$4 million loss it took on Arch in fiscal year 1995) (CO 12/16/96).

On January 19, 1995, three miners were slightly injured at Arch No. 37 when a coal seam burst. The seam gave way where miners were operating a continuous miner unit. Full production resumed on January 23, 1995 (CO 1/30/95).

Updated: May 1997

Status: Operating

Baker

GEOGRAPHIC DATA

Basin: Illinois

State: KY

Coalbed: Kentucky No. 13

County: Webster

CORPORATE INFORMATION

Current Owner: The Renco Group

Parent Company: The Renco Group

Previous Owner(s): Costain Coal, Inc.

Previous or Alternate Name of Mine: Pyro/Baker

MINE ADDRESS

Contact Name: Bill Adelman, Mine Manager

Phone Number: 502-333-4391

Mailing Address: P.O. Box 448

City: Sturgis

State: KY

ZIP: 42459

GENERAL INFORMATION

Number of Employees at Mine: 390

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.76% - 2.95%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,266

Depth to Seam (ft): 900

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	3.2	2.7	4.3	5.9
Estimated Total Methane Liberated (million cf/day):	1.0	0.7	1.4	1.9
Emissions from Ventilation Systems:	1.0	0.7	1.4	1.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	115	94	118	115

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Baker (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.12	0.18
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.8%	1.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.2%	0.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	44.3	177.2
Mine Electricity Demand:	34.2	141.7
Prep Plant Electricity Demand:	10.1	35.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	2.8	24.7
Assuming 60% Recovery Efficiency: ¹	4.2	37.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.3
Assuming 60% Recovery Efficiency (Bcf): ¹	0.4
Description of Surrounding Terrain: Open Hills	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Texas Gas Transmission	
Distance to Pipeline (miles): 8.3	Pipeline Diameter (inches): 26.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Baker (continued)

Summary of Recent News

The Baker mine is located near Sullivan, Kentucky in Webster County. Baker is 300 feet above the Wheatcroft mine and mines the No. 13 seam. Both operations were formerly owned by Costain Coal Co. They are now owned by the Renco Group. (CO 3/24/97.) In May 1997, Costain Coal was sold to Renco Inc., a unit of the conglomerate Renco Group (CO 8/26/96 p.1). Renco will pay \$34 million in cash and assume \$13 million of Costain's capitalized finance lease obligations (CO 12/16/96 p.1). The new owner has no other coal holdings, but does own WCI Steel in Warren, Michigan, Magnesium Corp. of America in Salt Lake City, Utah, a lead mine in Missouri, and A.M. General Corp. in South Bend, Indiana (CO 12/16/96 p.1).

Baker's coal has an average sulfur content of around 2.25%, and its 1994 production totaled 2,721,600 tons. Baker has an advantage over the neighboring Wheatcroft mine in that the sulfur content of the No. 13 seam is lower than that of Wheatcroft's No. 9 seam. The Baker mine's primary customers are the Tennessee Valley Authority (TVA) and Big Rivers Electric Corp.

In an effort to bolster its high-sulfur western Kentucky operations, Costain Coal made a number of capital improvements at the Baker/Wheatcroft complex in the early 1990s. The company installed a new longwall at Baker, constructed a 2,900 foot slope connecting Baker to Wheatcroft and a 5.5 mile rail line, and improved the Caney Creek washing plant. However, industry watchers doubted that the \$65 million in capital improvements would lower costs enough to compensate for the decreasing demand for Baker and Wheatcroft's high-sulfur coal (CO 9/12/94 p.8).

Baker began production in January 1995, with its newly-installed longwall producing an average of 14,000 tons per day with two active and one maintenance shifts (CO 3/6/95 p.3; CO 10/2/95 p.4). However, in March 1995, both the Wheatcroft and Baker mines were evacuated when a small fire started near a battery changing station, located 500 feet from the shaft entrance to Wheatcroft. There was a subsequent investigation into the cause of the fire (CW 3/20/95 p.6). Later that month, Costain laid off 63 workers on one of Baker's continuous miner sections supposedly due to the high ash content for the coal in that section of the mine, and because the new longwall was producing better than expected (CW 3/27/95 p.2).

Sales of Baker's coal began to pick up in mid-1995, and Costain Coal resumed profitability as a result of higher productivity and cost cutting, extended contracts with TVA and Big Rivers Electric Corp., and agreements with Emerald International to market Costain's high sulfur western Kentucky coal abroad (CW 5/8/95 p.2). In response to the instability in Wheatcroft's deliveries due to continued longwall problems, in June, 1995, TVA shifted the source of its coal supplies from Wheatcroft (which had been shipping to TVA's Paradise plant) to Baker. The Baker mine would thereafter ship 2 million tons of coal to TVA's Gallatin plant through the end of 1996 (CO 4/10/95 p.3). This exchange has been the source of some controversy as Green River Coal, a previous supplier to TVA, recently was in litigation with Costain arguing that the latter company had breached their contract (CO 4/10/95 p.3). In December 1995, PSI Energy announced that it would use coal from the Baker mine for testing at its Gallagher station (CW 12/11/95 p.1).

In July 1996, the Baker mine closed for several days due to a roof fall, but Costain was able to reschedule its shipments and did not have to invoke the *force majeure* clause in its contracts (CO 8/5/96 p.8). The mine continued to have problems through 1996 with excessive amounts of rock appearing in the pan line. The rock was debris from the unstable roof and because of its presence in the coal stream the speed of the shearer was slowed, thereby reducing the mine's output (CO 9/2/96 p.8).

In January 1997, Baker sustained another roof fall over the tailgate entry to the mine (CO 2/3/97 p.3). At the time Costain was considering altering its shipping schedules to its customers; TVA, Alabama Power, Alabama Electric and Emerald International, a coal trader. Up until the accident, the mine had been producing 15,500 tons per day, well above its budgeted level of 14,000 tons per day (CO 2/3/97 p.3).

Baker (continued)

Sales & Supply

In its July-September 1994 transactions, TVA purchased 189,000 tons of 3.0% sulfur coal from the Wheatcroft/Baker complex for its Gallatin operation, at \$29.35 per ton. TVA also bought 60,000 tons of 2.0% sulfur coal for its Johnsonville operation, at \$28.50 per ton (CW 1/23/95 p.7).

In its January-March 1995 transactions, TVA purchased 200,000 tons of 2.06% sulfur, 12,200 Btu/ton coal from the Baker/Wheatcroft complex, at \$26.90/ton (CW 10/16/95 p.7).

In June 1995, TVA shifted the source of its coal supplies from Wheatcroft (which had been shipping to TVA's Paradise plant) to Baker. Baker would thereafter ship 2 million tons of coal to the Gallatin plant through the end of 1996 (CO 4/10/95 p.3).

Updated: May 1997

Status: Operating

Camp No. 11

GEOGRAPHIC DATA

Basin: Illinois

State: KY

Coalbed: Springfield No. 5

County: Union

CORPORATE INFORMATION

Current Owner: Peabody Coal Company

Parent Company: Peabody Holding Co., Hanson PLC

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: James Roberts

Phone Number: 502-389-1007

Mailing Address: P.O. Box 120

City: Morganfield

State: KY

ZIP: 42437

GENERAL INFORMATION

Number of Employees at Mine: 247

Mining Method: Longwall

Year of Initial Production: 1990

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 2.81%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,230

Depth to Seam (ft): 1,370

Seam Thickness (ft): 5.2

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.5	2.1	2.5	3.1
Estimated Total Methane Liberated (million cf/day):	0.5	0.9	0.8	0.9
Emissions from Ventilation Systems:	0.5	0.9	0.8	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	119	153	115	106

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Camp No. 11 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.09
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.7%	1.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.2%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	23.2	92.9
Mine Electricity Demand:	18.0	74.3
Prep Plant Electricity Demand:	5.3	18.6
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.4	11.9
Assuming 60% Recovery Efficiency: ¹	2.0	17.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Open Hills	
Transmission Pipeline in County?: NA	
Owner of Nearest Pipeline: Central Illinois Light Company	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Camp No. 11 (continued)

Summary of Recent News

The Camp No. 11 mine, located in Union County, Kentucky, is owned by Peabody Coal Co., a subsidiary of the Peabody Group, which is the nation's largest coal producer (Keystone 1997). Camp No. 11 is part of Peabody's Camp complex, which includes the Camp No. 1 mine, the Camp No. 9 Preparation Plant, and the Camp Terminal, a barge-loading facility (Coal 4/94 p. 14, Coal 8/95 p. 5). Camp No. 11 opened in 1990, and produces coal that averages 11,487 Btu/lb with a sulfur content of 2.81 percent and an ash content of 8.40 percent (Keystone 1997).

In 1994, the company invested \$28 million to install a longwall mining system at the Camp No. 11 mine. The company anticipated that this longwall, which has a 750-foot face, 133 800-ton capacity shields, and a conveyor rate of 2,400 tons per hour, would both double the rate and lower the cost of coal production from the mine. The company implemented a new seven-day work schedule when longwall production began in July 1994 (Coal 4/94 p. 14, CO 8/1/94 p. 3, Coal 9/94 p. 20). However, the longwall production did not meet initial expectations for a number of reasons. In September 1994, the longwall miner, which works the Kentucky No. 9 seam, was flooded by excess water from the Kentucky No. 11 seam (CW 10/17/94 p. 7). Production halted again a week later due to a roof fall in the headgate section (CO 10/24/94 p. 4). In mid-October 1994, the longwall operated for a short time until roof pressure forced the company to move the longwall to an adjacent panel, which delayed production until the end of January 1995 (Coal 1/95 p. 7). By extending the use of continuous miners at both the Camp No. 11 and No. 1 mines and revising the shipping schedule with the Tennessee Valley Authority (TVA), the company reported that it had managed to offset some of the lost production while the longwall was out of commission (CO 1/16/95 p. 6).

In September 1995, the company laid off 160 hourly workers represented by UMWA as well as 20 salaried workers in an effort to reduce its payroll by 50 percent and improve the profitability of the Camp No. 11 mine. The company also reduced the number of production shifts at the mine from three to two, and restricted longwall production to five days per week (CW 7/10/95 p. 2, CO 7/17/95 p. 1, CW 8/7/95 p. 2). The company laid off an additional 27 workers from Camp No. 11 in May 1996 as a result of reducing the number of longwall development units from three to two (CO 5/27/96 p. 5). By implementing the Labor/Management Positive Change Process, part of the national agreement between the Bituminous Coal Operators Association and UMWA, the Camp complex implemented other cost-reduction measures and work-schedule changes that improved productivity at both the Camp No. 11 and Camp No. 1 mines (CO 7/31/95 p. 3, CW 8/7/95 p. 2, CO 9/9/96 p. 4).

Sales & Supply

TVA is the primary customer of the Camp complex. The Camp complex ships 5 million tons per year to TVA's Cumberland plant under a term contract that runs through 1999 (CO 8/1/94 p. 3, Coal 11/94 p. 33). In the spring of 1995, TVA renegotiated this contract, which resulted in a price reduction from \$28 to \$21.14 per ton. However, TVA also agreed to purchase an additional one million tons per year from the Camp complex at a price of about \$19.88 per ton, including a dock handling fee of about \$0.50 per ton (CW 3/6/95 p. 1). In 1994, TVA awarded a six-year Requisition 30 coal contract for 20,000 tons per week from the Camp complex (CW 11/14/94 p. 1). In the first quarter of 1995, the Camp complex supplied a spot order of 156,000 tons to TVA (CW 10/16/95 p. 7). The Camp complex may also supply a portion of Peabody's contract with Louisville Gas and Electric (CO 4/22/96 p. 4). In July 1995, the company announced that it had modified production so that the Camp No. 11 and No. 1 mines were each responsible for about 50 percent of total production from the Camp complex (CO 7/17/95 p. 1).

Updated: May 1997

Status: Operating

Clean Energy No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Pond Creek

County: Pike

CORPORATE INFORMATION

Current Owner: Sidney Coal Company

Parent Company: A. T. Massey Coal Co., Inc.

Previous Owner(s): Clean Energy Mining Co.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Charles I. Bearse, III

Phone Number: 606-353-4197

Mailing Address: P.O. Box 267

City: Sidney

State: KY

ZIP: 41564

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Room & Pillar

Year of Initial Production: 1994

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: NA

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.0	0.6	1.0	1.3
Estimated Total Methane Liberated (million cf/day):	0.0	0.8	0.9	1.1
Emissions from Ventilation Systems:	0.0	0.8	0.9	1.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	0	500	324	312

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Clean Energy No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.07	0.11
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.1%	3.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.5%	0.7%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	7.5	30.9
Mine Electricity Demand:	7.5	30.9
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.7	14.6
Assuming 60% Recovery Efficiency: ¹	2.5	21.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Hills	
Transmission Pipeline in County?: NA	
Owner of Nearest Pipeline: Columbia Gas of Kentucky, Inc.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Clean Energy No. 1 (continued)

Summary of Recent News

There is no further information available for this mine.

Updated: May 1997

Status: Operating

Dotiki

GEOGRAPHIC DATA

Basin: Illinois

State: KY

Coalbed: Springfield No. 5

County: Webster

CORPORATE INFORMATION

Current Owner: Webster County Coal Corp.

Parent Company: MAPCO Coal, Inc. (Beacon Energy Investment Fund)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Billy Mitchell, General Mine Foreman

Phone Number: 502-667-2205

Mailing Address: 1758 State Route 874

City: Clay

State: KY

ZIP: 42404

GENERAL INFORMATION

Number of Employees at Mine: 267

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 16

Sulfur Content of Coal Produced: 2.87%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,710

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.5	2.5	2.5	3.3
Estimated Total Methane Liberated (million cf/day):	0.6	0.6	0.6	0.7
Emissions from Ventilation Systems:	0.6	0.6	0.6	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	89	88	86	74

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Dotiki (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.04	0.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.5%	0.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	24.8	99.3
Mine Electricity Demand:	19.2	79.5
Prep Plant Electricity Demand:	5.6	19.9
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.0	8.9
Assuming 60% Recovery Efficiency: ¹	1.5	13.3

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain: Open Hills	
Transmission Pipeline in County?: NA	
Owner of Nearest Pipeline: Columbia Gas of Kentucky, Inc.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Dotiki (continued)

Summary of Recent News

Dotiki is a room-and-pillar mine located in Webster County, Kentucky. The mine is a non-union operation and is owned by MAPCO Coal, which operates a number of coal mines in Kentucky, Illinois, Maryland and Virginia (CW 11/16/96).

MAPCO Coal had operating profits of \$35.9 million in 1994, down from \$46.9 million in 1993. Costs were said to have risen due to capital expenditures at the Dotiki and Pattiki mines and a longwall move at Mettiki late in 1994 (CO 2/6/95 p.1).

In November 1994, the board of the Tennessee Valley Authority (TVA) was asked to approve seven six-year Requisition 30 coal supply contracts, including one with MAPCO/Webster County's Dotiki mine. Dotiki began shipping 24,000 tons per week to TVA's Paradise power plant, in early 1995, for a total of 1.25 million tons per year (CW 11/28/94 p.4). Other companies that signed TVA contracts included Sextet Mining Corp., Ken American Resources, Pyramid Mining Inc., Andalex Resources, Cyprus Amax Coal Sales, and Peabody Coal Co. (CW 11/14/94 p.1). The TVA agreement to supply coal to the Paradise plant allowed MAPCO to make a number of capital improvements at the Dotiki mine. By late 1995, construction had begun on a new bathhouse, and a new mine shaft was expected to be operable by mid-1996, at a total cost of \$7 million (CO 8/7/95 p.6).

In early 1995, MAPCO closed its Retiki mine in Henderson County, KY, but the company agreed to ship replacement coal to Big Rivers Electric to fulfill the final year of their contract, which expired in January 1996. Replacement coal was to come from the Dotiki mine as well as some third party sources; for example, in August 1995, Dotiki shipped 96,700 tons of coal to Big Rivers' Green power plant, at a price of \$27.36 per ton. Retiki's closing and the agreement on replacement coal shipments were arranged to settle a contract dispute between MAPCO and Big Rivers over closing costs at the mine (CO 2/6/95 p.1).

In March 1995, MAPCO began shipping coal from Dotiki by truck to the Kanipe terminal on the Ohio River. The coal had previously been shipped via rail, by CSX Transportation, to Kanipe, where it was taken by barge down the Ohio and Mississippi rivers to the Intercoastal Waterway, then moved by rail from Port St. Joe, FL to the Seminole's Palatka power plant. By mid-April 1995, the success of the new system prompted MAPCO to increase the amount shipped by truck from 6,200 to 12,400 tons of coal per week, about half of the total amount shipped to Seminole (CO 4/17/95 p.6). The change in shipments from Dotiki resulted from a dispute between MAPCO and CSX over transportation costs (CO 10/9/95 p.3).

MAPCO's 3-year contract with Seminole for 450,000 tons per year from the Dotiki mine ended in December 1995. To replace that contract, CONSOL was chosen to supply 144,000 tons to Seminole, with an option for an additional 288,000 tons. However, MAPCO is still the primary supplier to Seminole through another contract for 2.2 million tons per year (CO 10/9/95 p.3).

In September 1995, Dotiki's prep plant was closed for one day when a worker was killed while operating a bulldozer at the plant's raw coal stockpile. There has been an investigation into the cause of the accident (CO 9/18/95 p.5).

MAPCO Coal was purchased by Beacon Group Energy Investment Fund in late 1996. Beacon paid \$250 million for MAPCO Coal (formerly owned by MAPCO Inc.), and MC Mining, which holds the assets for Scotts Branch Coal. Included in the sale were MAPCO Coal's Dotiki mine in western Kentucky, Martiki and Pontiki in eastern Kentucky, Pattiki in Illinois, Mettiki in Maryland, and Permac and Racefork in Virginia. All of the mines are non-union, and none are currently experiencing strikes, slowdowns, or other work actions (CW 11/18/96 p.4). MAPCO also signed a non-competition agreement with Beacon in which it cannot produce, import, sell, or distribute coal anywhere in the world until two years after the sale (CW 11/18/96 p.4).

Dotiki (continued)

Sales & Supply

In July 1995, MAPCO began a new contract with the TVA's Paradise power plant, in which Dotiki will supply 1.25 million tons of raw coal per year (CO 8/7/95 p.6).

Updated: May 1997

Status: Operating

Freedom Energy No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Pond Creek

County: Pike

CORPORATE INFORMATION

Current Owner: Sidney Coal Company

Parent Company: A. T. Massey Coal Co., Inc.

Previous Owner(s): Aero Energy Co., Inc.

Previous or Alternate Name of Mine: Aero Energy No. 1

MINE ADDRESS

Contact Name: Charles I. Bearse, III

Phone Number: 606-353-4197

Mailing Address: P.O. Box 262

City: Toler

State: KY

ZIP: 41569

GENERAL INFORMATION

Number of Employees at Mine: 67

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.67%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 12,822

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.9	1.5	1.1	1.1
Estimated Total Methane Liberated (million cf/day):	0.4	0.7	0.8	0.7
Emissions from Ventilation Systems:	0.4	0.7	0.8	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	75	168	255	232

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Freedom Energy No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.05	0.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.6%	2.4%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	6.4	26.4
Mine Electricity Demand:	6.4	26.4
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.1	9.3
Assuming 60% Recovery Efficiency: ¹	1.6	13.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas of Kentucky, Inc.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Freedom Energy No. 1 (continued)

Summary of Recent News

The Freedom Energy No. 1 mine is located in Pike County, Kentucky. The mine is a room-and-pillar operation that produces medium-sulfur (1.67%) steam and metallurgical coal. The mine produced 1,521,790 tons in 1994 and 1,084,250 tons in 1995 (1997 Keystone Coal Industry Manual).

No further information on this mine is available at this time.

Updated: May 1997

Status: Operating

Pontiki No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Pond Creek

County: Martin

CORPORATE INFORMATION

Current Owner: Pontiki Coal Corp.

Parent Company: MAPCO Coal, Inc. (Beacon Energy Investment Fund)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Charlie Wesley, Vice President Operations

Phone Number: 606-395-5348

Mailing Address: P.O. Box 801, Route 1401

City: Lovely

State: KY

ZIP: 41231

GENERAL INFORMATION

Number of Employees at Mine: 288

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 21

Sulfur Content of Coal Produced: 0.60% - 0.90%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,800

Depth to Seam (ft): 425

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.8	0.6	1.1	1.2
Estimated Total Methane Liberated (million cf/day):	0.6	0.7	0.7	0.6
Emissions from Ventilation Systems:	0.6	0.7	0.7	0.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	264	449	242	177

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pontiki No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

Assumed Potential Recovery Efficiency¹

(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.04	0.05
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.2%	1.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	8.7	34.7
Mine Electricity Demand:	6.7	27.7
Prep Plant Electricity Demand:	2.0	6.9
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.8	7.4
Assuming 60% Recovery Efficiency: ¹	1.3	11.1

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain:	High Hills/Low Mountains
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Columbia Gas Transmission
Distance to Pipeline (miles):	2.0
Pipeline Diameter (inches):	6.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Pontiki No. 1 (continued)

Summary of Recent News

Pontiki mine (comprised of mines 1 and 2) in eastern Kentucky is owned by Pontiki Coal, a division of MAPCO Coal. In the last few years, Pontiki has both negatively and positively impacted the operating profits of MAPCO Coal.

In 1994, equipment failures at the Pontiki mine were partially responsible for a decline in MAPCO profits. Profits fell from \$47 million in 1993 to approximately \$36 million in 1994 (CO 10/16/95). However, Pontiki redeemed itself the following year with improved productivity that helped boost profits the first quarter of 1996. MAPCO Coal produced operating profits of \$10.2 million for the quarter and sold a record 4.3 million tons (CW 5/6/96).

The lucrative profits generated by MAPCO Coal may have lead to the purchase of its stock by the Beacon Group. On June 28, 1996, the Beacon Group Energy Investment Fund acquired the stock of MAPCO Coal and MC Mining for \$250 million through a stock purchase agreement with MAPCO Inc. (CW 11/18/96).

Pontiki was one of several mines transferred with MAPCO Coal's stock; the others were Dotiki in western Kentucky, Martiki in eastern Kentucky, Mettiki in Maryland, Pattiki in southern Illinois, and Permac and Racefork in Virginia. As part of the sale, MAPCO Inc. signed a non-competition agreement that prevents MAPCO Inc. and its subsidiaries and affiliates from producing, importing, selling, or distributing coal anywhere in the world (except Indonesia) for a period of two years after the sale date (CW 11/18/96).

Also as part of the sale, MAPCO assured the Beacon Group at the time of the final closing that none of its employees were unionized and that there were no strikes, slowdowns, or court filings pending against the MAPCO Coal companies (CW 11/18/96). Traditionally, Pontiki has been a non-union mine. However, the UMWA did attempt to organize the mine several years ago. In March 1993, Pontiki employees held a one-day strike after their health benefits were reduced. Soon after, the UMWA began organizing efforts at the mine. On June 15, 1993, the UMWA requested to hold union elections after 70 percent of the workforce signed cards supporting the UMWA (CW 6/21/93). In the end, the UMWA lost in a 101 to 101 tie and Pontiki remains a non-union mine to this day (CO 8/8/94).

Sales & Supply

In April 1996, Pontiki lost a second opportunity to supply Clemson University with stoker coal. The State of South Carolina opted to extend its contract with Converse & Co. for another year. In the previous year, Woodruff Coal offered Pontiki rail-delivered coal at an FOB mine price of \$29.74 per ton and trucked Pontiki coal at a delivered price of \$48.24 per ton. Clemson's ash specification is 6.5 percent, however, the ash content of the Woodruff/Pontiki coal was 7.9 percent (CW 4/8/96). Converse also has the advantage of a two percent in-state preference.

Pontiki also put in a bid for a 240,000 ton per year, 2-4 year compliance coal contract for the Somerset (MA) Unit No. 6 (CW 6/10/96). The bid was due on June 21, 1996. Montaup Electric tested 29,000 tons of Pontiki coal for compliance with specifications of 12,900-13,000 Btu/lb., 0.75 percent sulfur, 6.3 percent average ash, 9 percent ash maximum and 47-60 grind. The 14,600 tons delivered in February for testing originated on NS and cost \$46.18 per ton (CO 6/17/96).

In 1995, Pontiki lost a one-year, 30,000 ton contract for the University of Massachusetts to A T Massey Coal Sales. Pontiki bid \$33 per ton and A T Massey won with a bid using New Ridge coal at \$32.80 per ton FOB and Long Fork coal at \$30 per ton FOB (CW 7/3/95).

In 1994, Pontiki shipped coal on the spot market to Baltimore Gas & Electric, Delmarva Power & Light, Georgia Power, Kentucky Power, and Pennsylvania Power & Light (CO 10/24/94). Also, in November 1994, Pontiki supplied 30,000 tons of spot coal to the Dean H. Mitchell generating station of the Northern Indiana Public Service Co. (CW 11/7/94).

Pontiki No. 1 (continued)

Overall, MAPCO Coal enjoyed total revenues \$124.3 million for the first quarter of 1996 compared with \$102.3 million in 1995. MAPCO sold 4.3 million tons for the quarter compared with 3.43 tons for the same quarter of the previous year (CW 5/6/96).

Updated: May 1997

Status: Operating

Pontiki No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Pond Creek

County: Martin

CORPORATE INFORMATION

Current Owner: Pontiki Coal Corp.

Parent Company: MAPCO Coal, Inc. (Beacon Energy Investment Fund)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Bret Hardwick

Phone Number: 606-395-5352

Mailing Address: HC 67, Box 387

City: Lovely

State: KY

ZIP: 41231

GENERAL INFORMATION

Number of Employees at Mine: 256

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.60% - 0.73%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,900

Depth to Seam (ft): 425

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.7	0.8	0.8	0.8
Estimated Total Methane Liberated (million cf/day):	0.4	0.5	0.3	0.9
Emissions from Ventilation Systems:	0.4	0.5	0.3	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	216	220	141	408

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pontiki No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.09
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.8%	4.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.6%	0.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	6.0	24.1
Mine Electricity Demand:	4.7	19.3
Prep Plant Electricity Demand:	1.4	4.8
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.4	11.9
Assuming 60% Recovery Efficiency: ¹	2.0	17.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: High Hills/Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 2.0	Pipeline Diameter (inches): 6.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Updated: May 1997

Status: Closed

Wheatcroft No. 9

GEOGRAPHIC DATA

Basin: Illinois

State: KY

Coalbed: Kentucky No. 9/Springfield No. 5

County: Webster

CORPORATE INFORMATION

Current Owner: The Renco Group

Parent Company: The Renco Group

Previous Owner(s): Costain Coal, Inc.

Previous or Alternate Name of Mine: Pyro No. 9 Wheatcroft

MINE ADDRESS

Contact Name: Bill Adelman, Mine Manager

Phone Number: 502-333-4391

Mailing Address: P.O. Box 448

City: Sturgis

State: KY

ZIP: 42459

GENERAL INFORMATION

Number of Employees at Mine: 467 ¹

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 1.66% - 5.18%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,256

Depth to Seam (ft): 900

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	3.6	2.8	1.1	0.0
Estimated Total Methane Liberated (million cf/day):	3.2	3.5	3.3	0.1
Emissions from Ventilation Systems:	1.9	2.1	2.0	0.1
Estimated Methane Drained:	1.3	1.4	1.3	0.0
Estimated Specific Emissions (cf/ton):	321	456	1,117	0

Estimated Current Drainage Efficiency: Mine closed

Drainage System Used: Vertical Gob (Mine closed; drainage system not active)

¹ Number of employees based on when mine was in operation.

Wheatcroft No. 9 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.22	0.32
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	8.0%	12.0%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.8%	2.7%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	8.2	32.7
Mine Electricity Demand:	6.3	26.1
Prep Plant Electricity Demand:	1.9	6.5
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency:	5.1	44.2
Assuming 60% Recovery Efficiency:	7.6	66.4

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf):	0.5
Assuming 60% Recovery Efficiency (Bcf):	0.7
Description of Surrounding Terrain: Open Hills	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Texas Gas Transmission	
Distance to Pipeline (miles): 8.3	Pipeline Diameter (inches): 26.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

Wheatcroft No. 9 (continued)

Summary of Recent News

The Wheatcroft mine is located in Webster County, in western Kentucky. The mine is part of the former William Station mine and also connects to the nearby Baker mine. All three of the mines were formerly owned by Costain Coal Co. Costain Coal was sold to the Renco Group in March 1997. (CO 3/24/97). The mine is equipped with a longwall mining system and produced 2.8 million tons of coal in 1994. Wheatcroft mine's primary customer is the Tennessee Valley Authority (TVA). The mine was closed in June 1995 (CW 6/12/95, p.6).

Apparently, Costain closed the Wheatcroft mine due to an unstable market for its product (CO 10/2/95 p.4). In April 1995, Costain Coal signed an agreement to ship 4 million tons of coal to TVA over the next two years replacing a contract, expiring in July 1995, to supply the Colbert and Johnsonville power plants (CO 5/8/95 p.2). However, in March 1995, the company issued WARN notices to all of its employees in western Kentucky, and reductions in work force were expected primarily at the Wheatcroft mine (CO 4/10/95). In June 1995, Costain Coal Co. laid off 150 workers at Wheatcroft because of poor market conditions. At the time the company stated that it expected more layoffs after crews finished moving and securing the longwall, and completed cutting entries into a new portal (CO 6/12/95 p.1).

By October 1995, Costain Coal had resumed profitability, in part due to increased productivity stemming from the closing of Wheatcroft and the installation of a longwall at the nearby Baker mine (CO 10/2/95 p.4). In December 1996, Costain Coal was sold to Renco Group, a conglomerate based in New York for \$34 million (CO 8/26/96 p.1; CO 12/16/96 p.4).

Costain is planning to restart Wheatcroft sometime in early 1997, with one continuous miner section producing around 40,000 tons per month. TVA has expressed interest in signing a term contract for coal from the Wheatcroft mine when it begins to pick up production (CO 2/3/97 p.3).

On September 13, 1989, ten miners were killed in a methane explosion at the former William Station mine, which later became part of Wheatcroft. Safety issues continued to cause concern at the Wheatcroft mine up until its closing. In March 1995, both the Wheatcroft and Baker mines were evacuated when a small fire started near a battery changing station, located 500 feet from the shaft entrance to the Wheatcroft mine. There has been an investigation into the cause of the fire (CW 3/20/95 p.6).

Updated: May 1997

Status: Closed

Wolf Creek No. 4

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Warfield/Pond Creek

County: Martin

CORPORATE INFORMATION

Current Owner: Wolf Creek Collieries

Parent Company: Zeigler Coal Holding Company

Previous Owner(s): Shell Mining

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Larry Misinay

Phone Number: 606-395-5361

Mailing Address: Caller No. 802

City: Lovely

State: KY

ZIP: 41231

GENERAL INFORMATION

Number of Employees at Mine: 200¹

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 0.64% - 2.56%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,800

Depth to Seam (ft): 600

Seam Thickness (ft): 4.6

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.0	1.9	1.1	0.0
Estimated Total Methane Liberated (million cf/day):	0.7	1.4	0.8	0.4
Emissions from Ventilation Systems:	0.7	1.4	0.8	0.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	128	266	285	0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

¹ Number of employees based on when mine was in operation.

Wolf Creek No. 4 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.08
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.9%	2.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.7%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	8.2	32.7
Mine Electricity Demand:	6.3	26.2
Prep Plant Electricity Demand:	1.9	6.5
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ²	1.3	11.3
Assuming 60% Recovery Efficiency: ²	1.9	16.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.1
Assuming 60% Recovery Efficiency (Bcf): ²	0.2
Description of Surrounding Terrain: High Hills/Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 1.7	Pipeline Diameter (inches): 6.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Wolf Creek No. 4 (continued)

Summary of Recent News

Zeigler's Wolf Creek complex in Kentucky includes a unit train load-out, a wash plant, and a deep mine of low-sulfur coal. Wolf Creek has encountered many production and geologic problems, including flooding, poor mining conditions, methane build-up, questionable reserve life, and a longwall relocation and eventual removal. The flooding began in early 1993 and was finally remedied in September 1994 (CO 10/10/94). Due to these and other problems regarding its long-term contract with Carolina Power & Light the Wolf Creek mine has been closed. However, recent reports indicate that a new mine may be opened at Wolf Creek.

Wolf Creek is under contract to ship 2 million tons per year or approximately 166,667 tons per month to Carolina Power & Light (CP&L) (CO 11/7/94). The contract expires in 2004, with possible extensions through 2009. Zeigler exceeded the schedule in the first six months, with 1,067,000 tons of Wolf Creek coal. However in July 1994, shipments fell to 113,700 tons. Zeigler claimed this was a result of miner's vacation. But, output continued to fall due to geological problems, including unstable roof and water seepage from the mined-out seam above. Wolf Creek was unable to resume normal shipments in August, shipping only 69,400 tons to CP&L (CO 11/7/94).

Wolf Creek's ability to supply both the quantity and quality of coal under the contract was questionable. In its prospectus, Zeigler claimed Wolf Creek contains 24.3 million tons of economically recoverable reserves in today's market. Various industry sources believed, however, Wolf Creek would have trouble servicing the contract with economically recoverable coal through 2004 (CO 10/17/94).

Wolf Creek's single longwall had operated in the Alma seam. Wolf Creek relocated its longwall from the northern to the southern end of the reserve because of low seam height and bad top. After relocating the longwall, Wolf Creek experienced further troubles. The longwall had to slow down to avoid extracting rock from an unstable roof. The seam above the seam of the longwall had inadvertently been cut into pushing a lot of water into the mine. In July 1995, Wolf Creek sold the longwall and replaced it with three continuous miners (CW 5/8/95). Zeigler invested about \$12 million in new mining equipment including continuous haulage equipment on two of the sections (CW 5/8/95).

Regardless of which mining method Wolf Creek used, it needed to satisfy its commitment to CP&L immediately or risk losing the entire contract. There was speculation that CP&L wanted out of the contract for many reasons. On November 4, 1994, CP&L suspended shipments from Wolf Creek Collieries' No. 4 mine on the grounds that the coal's sulfur content was below specification. The low sulfur content could affect the performance of the utility's electrostatic precipitators and increase particulate emissions (CW 12/5/94). CP&L argued that Zeigler breached its long-term contract by shipping coal with a lower sulfur content than specified. CP&L insisted that the dispute centered only on coal quality, and not price. Wolf Creek coal is, however, CP&L's most expensive coal. The delivered price of Wolf Creek's contract coal to CP&L costs \$53-59/t. FOB mine is \$42-43/t (CW 12/5/94).

In November 1994, Zeigler and CP&L sued each other in separate courts after Wolf Creek advised the utility that it would deliver higher-sulfur coal by blending coal from other reserves under the control of Wolf Creek and the adjacent Kermit property. CP&L did not agree to this, stating such blending is not permitted by the contract (CW 12/5/94). A federal judge subsequently ordered CP&L to accept coal from Wolf Creek that met contract specifications. He also ordered the dispute to arbitration, giving both parties until March 31, 1995, to reach an agreement (CW 4/10/95).

The two parties settled the dispute out of court in April 1995. The new contract relaxed the sulfur specifications, lowered the mine price and gave Zeigler sourcing flexibility. Zeigler agreed to price reductions, starting at 5 percent for 1995 followed by further unspecified reductions throughout the course of the contract (CW 5/8/95). In addition, CP&L cut its coal deliveries by 500,000 tons per year from Wolf Creek Collieries. With the gained sourcing flexibility, Zeigler may supply 1.5 million tons per year from any mine on Norfolk Southern Railway and another 500,000 tons per year from any mine served by CSX Transportation. The agreement provides for 1.5 million tons per year from Wolf Creek, a level which is consistent with Wolf Creek's switch from longwall mining to continuous miners (CO 5/8/95).

Wolf Creek No. 4 (continued)

Although the new contract defined quantity and quality levels which Wolf Creek could provide, high operating costs and an extremely depressed spot market for steam coal still posed problems. Wolf Creek needed to reduce costs so that Zeigler and its sales arm, Franklin Coal Sales, would not turn to other sources to fulfill the contract (CO 5/8/95). Wolf Creek is Zeigler's highest cost source of coal. Prior to the contract dispute Wolf Creek's costs were in the mid to high \$30s. Even with dramatic reductions it would be very difficult for Wolf Creek to bring down costs to the new contract base price of ~\$26 per ton (CO 8/14/95).

Some believe that CP&L is paying Zeigler a settlement fee which covers much of the decline in the billing price (CO 8/14/95). If this is correct, Zeigler does not necessarily have to profit from the CP&L contract. The profit may be contained in the settlement payments. Thus, if Wolf Creek cannot lower its costs to match the lower base price then Zeigler may buy third-party coal (CO 8/14/95).

As predicted, Zeigler solicited proposals from selected coal suppliers served by Norfolk Southern Railway (CO 8/14/95). And after securing replacement coal from two producers, Zeigler Coal halted production at Wolf Creek on October 1, 1995 (CO 10/9/95). Zeigler said that the mine would remain on hot idle, pending further evaluation of the mine's costs and its ability to compete within the current market. Unless Zeigler secures a long-term source of NS-origin coal for the CP&L contract, it may need to keep the Wolf Creek option. It is possible that the option could be sustained even if the mine were sold. As for the Wolf Creek preparation plant, Brooks Run Coal, a unit of Coastal Corp.'s ANR Coal, purchased it from Oneida Coal. Last reported, Brooks was studying whether to operate Wolf Creek (CO 9/18/95).

Soon after the contract settlement and the decision to use third-party coal, Wolf Creek laid off 219 employees -- 188 hourly and 31 salaried (CW 5/8/95). The layoff followed the furlough of 57 workers because of a buildup of explosive methane gas in the 4-East section of the mine (CW 5/1/95). The mine is down to 77 workers, 60 underground and 17 at the prep plant (CW 5/8/95). The United Mine Workers represent the hourly employees. The laid-off employees took a stand and requested panel rights at other Zeigler mines (CO 4/8/96). However, they met defeat. Wolf Creek's parent company SMC Mining is a sister company to the parent companies of Old Ben and Marrowbone. Because Zeigler is not a signatory to the national agreement and each subsidiary signed the agreement independently, the federal arbitrator ruled that no panel rights could be granted. There are approximately ten other non-signatory companies under the SMC umbrella where union miners might have job rights (CO 4/8/96).

In December 1995, the status of Wolf Creek remained idle while various long-term options were being considered. Zeigler Coal Holding wrote off \$25 million of Wolf Creek assets (CO 12/18/95) and sources claim Zeigler is seeking a buyer for the property (CO 10/9/95). Companies with coal reserves contiguous to or near Wolf Creek include Arch, Ashland Coal, CONSOL, MAPCO Coal, A.T. Massey, Pittston Coal, and Quaker Coal (CO 9/11/95).

In April 1996, reports stated that James Simpkins and Walden Hatfield, who are contract miners for major companies in Central Appalachia, may have opened a new mine at Wolf Creek. Zeigler was already in the process of reclaiming Wolf Creek and had extracted underground equipment and was sealing the Caney portal. The plan was for Zeigler, or a contract miner, to start over at the bottom of the slope. New mains would be driven into an undeveloped part of the reserve. Production was projected to begin sometime in the Summer of 1996 (CO 4/8/96). However, the resumption of production did not occur and as recently as February 1997 rumors indicated that Zeigler Coal Holding was once again talking to contractors about reopening Wolf Creek Collieries (CO 2/3/97).

6. Profiled Mines (continued)

New Mexico Mines

Cimarron

Updated: May 1997

Status: Closed

Cimarron

GEOGRAPHIC DATA

Basin: Western (Raton Mesa)

State: NM

Coalbed: Left Fork (U)

County: Colfax

CORPORATE INFORMATION

Current Owner: Pittsburgh & Midway Coal Mining Co.

Parent Company: Chevron

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: York Canyon

MINE ADDRESS

Contact Name: M.A. Provenza, Mine Manager

Phone Number: 505-445-6000

Mailing Address: P.O. Box 100

City: York Canyon

State: NM

ZIP: 87740

GENERAL INFORMATION

Number of Employees at Mine: 189 ¹

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 0.56%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,300

Depth to Seam (ft): 550

Seam Thickness (ft): 8.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.8	0.9	0.6	0.0
Estimated Total Methane Liberated (million cf/day):	0.4	0.5	0.3	0.0
Emissions from Ventilation Systems:	0.4	0.5	0.3	0.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	192	192	171	0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

¹ Number of employees based on when mine was in operation.

Cimarron (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.02	0.03
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.2%	1.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Raton Public Service Co.

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	4.8	19.2
Mine Electricity Demand:	3.7	15.4
Prep Plant Electricity Demand:	1.1	3.8
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ²	0.5	4.0
Assuming 60% Recovery Efficiency: ²	0.7	6.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.0
Assuming 60% Recovery Efficiency (Bcf): ²	0.1
Description of Surrounding Terrain: Rolling Hills	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Raton Natural Gas	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Raton Power Plant

Distance to Plant (miles): NA Boiler Capacity (MW): 11.0

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Cimarron (continued)

Summary of Recent News

The Cimarron underground mine is part of the York Canyon complex in Colfax County, New Mexico. York Canyon is comprised of both underground and surface mines, producing around 2 million tons of 0.56%-sulfur coal per year. The mine is currently closed as a result of difficult geological conditions.

Pittsburgh and Midway Coal Mining Co. (P&M) acquired the mining rights to the York Canyon complex in 1989 from Kaiser Coal Co. during bankruptcy proceedings, and made a number of improvements to both its underground and surface mines (CW 3/13/95 p.3). The Cimarron mine, however, has had a number of roof problems, floor heaves, and sand channels in the past few years and was operating with a "1984-model" longwall up until its closing (CW 3/13/95 p.3).

In March 1995, P&M was forced to reduce the tons delivered in its long-term contract to Wisconsin Electric Power's (WEPCO) Oak Creek plant. Instead of delivering 2 million tons per year to Oak Creek through 2007, P&M would now ship only 800,000 tons per year beginning in 1996 (CW 3/13/95 p.3). The reduction was necessary because of the uncertainty surrounding coal production from the Cimarron mine.

Cimarron was idled in October 1995, due to difficult mining conditions (CO 12/18/95 p.8). At the time P&M estimated that its Ancho surface mine, which produces around 1.3 million tons annually, would be able to make up for Cimarron's closure and cover deliveries to the Oak Creek plant. Currently, P&M appears to be exploring other projects in the York Canyon area, and the company has formed a new business development unit to further explore domestic and international mining opportunities (CO 12/18/95 p.1).

6. Profiled Mines (continued)

Ohio Mines

Meigs No. 2
Meigs No. 31
Nelms Cadiz Portal
Powhatan No. 4
Powhatan No. 6

Updated: May 1997

Status: Operating

Meigs No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: OH

Coalbed: Clarion No. 4A

County: Meigs

CORPORATE INFORMATION

Current Owner: Ohio Power Co., Southern Ohio Coal Co.

Parent Company: American Electric Power

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: L. Fultz, General Mine Supervisor

Phone Number: 614-286-5051

Mailing Address: P.O. Box 490

City: Athens

State: OH

ZIP: 45701

GENERAL INFORMATION

Number of Employees at Mine: 532

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 16

Sulfur Content of Coal Produced: 3.40%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 11,300

Depth to Seam (ft): 350

Seam Thickness (ft): 4.1 - 5.8

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.0	2.3	2.4	2.9
Estimated Total Methane Liberated (million cf/day):	0.8	0.7	0.7	0.5
Emissions from Ventilation Systems:	0.8	0.7	0.7	0.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	143	112	106	62

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Meigs No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.03	0.05
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.5%	0.7%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Columbus Southern Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	17.1	70.6
Mine Electricity Demand:	17.1	70.6
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.8	6.6
Assuming 60% Recovery Efficiency: ¹	1.1	10.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain: Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Tennessee Gas Pipeline	
Distance to Pipeline (miles): 0.7	Pipeline Diameter (inches): 36.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Ohio Power Gavin Plant

Distance to Plant (miles): 15.0

Boiler Capacity (MW): 1,300.0

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Meigs No. 2 (continued)

Summary of Recent News

The Meigs No. 2 and No. 31 mines are located five miles apart in Meigs County, Ohio. The owner/operator of the mines is Southern Ohio Coal Co. (SOCCo), a subsidiary of American Electric Power (AEP). The mines work the Clarion 4A seam, producing high-volatile bituminous coal with a sulfur content of around 3.4%. Both Meigs mines are longwall operations, and both feed into a prep plant near the No. 31 mine (Coal 12/95 p.39). The Meigs complex supplies around 4 million tons of coal annually to the 2,600 MW Gavin power plant, which is owned by Ohio Power. Ohio Power is a subsidiary of AEP (CW 1/16/95 p.3). Gavin is one of the largest coal-fired power plants in the U.S. (Coal 4/95 p.11).

Coal from the Meigs No. 2 mine is transported, via an overland conveyor system, to Meigs No. 31 where coal from both mines is fed into a 2,200 ton per hour prep plant (Coal 12/95 p.39).

During the summer of 1995 rumors began circulating that AEP would close the Meigs mines due to their high cost (CO 7/24/95 p.7). But, in September 1995, the U.S. Securities and Exchange Commission granted AEP permission to sell over 800,000 tons per year of excess coal through the year 2000, including 375,000 tons per year from the Meigs mines (CO 9/25/95 p.6).

In February 1996, AEP announced the expected years of closure for its four affiliate mines. Meigs No. 2 and No. 31 are slated to be closed in 2009, later than AEP's other mines, because the Gavin plant is equipped with scrubbers. Phase II of the 1990 Clean Air Act, which goes into effect in 2000, will tighten restrictions on SO₂ emissions, and is likely to affect AEP's high-sulfur mines, including the Meigs mines (CO 2/19/96 p.5).

Despite the issues surrounding the operation of the Meigs mines mentioned above, AEP and SOCCo have managed to make several technological improvements to the mines over the past few years. AEP installed four radio-controlled roof bolting machines early in 1995, the first of their kind used in the coal industry (Coal 3/95 p.17). Later that year the company modified its overland conveyor to reduce belt slippage by installing an Australian-designed ceramic pulley (Coal 12/95 p.39).

Sales & Supply

As mentioned above, the Meigs mines supply coal to AEP's Gavin power plant. In September 1995, the U.S. Securities and Exchange Commission granted AEP permission to sell excess coal through the year 2000, including 375,000 tons per year from the Meigs mines (CO 9/25/95 p.6).

Updated: May 1997

Status: Operating

Meigs No. 31

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: OH

Coalbed: Clarion No. 4A

County: Meigs

CORPORATE INFORMATION

Current Owner: Ohio Power Co., Southern Ohio Coal Co.

Parent Company: American Electric Power

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: T. Ervin, General Mine Supervisor

Phone Number: 614-286-5051

Mailing Address: P.O. Box 490

City: Athens

State: OH

ZIP: 45701

GENERAL INFORMATION

Number of Employees at Mine: 295

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 16

Sulfur Content of Coal Produced: 3.40%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,300

Depth to Seam (ft): 300

Seam Thickness (ft): 4.1 - 5.4

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	2.0	2.3	3.0
Estimated Total Methane Liberated (million cf/day):	0.7	0.7	0.9	1.1
Emissions from Ventilation Systems:	0.7	0.7	0.9	1.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	150	126	142	134

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Meigs No. 31 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.07	0.11
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.0%	1.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.2%	0.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Columbus Southern Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	22.6	90.2
Mine Electricity Demand:	17.4	72.2
Prep Plant Electricity Demand:	5.1	18.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.7	14.6
Assuming 60% Recovery Efficiency: ¹	2.5	21.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Tennessee Gas Pipeline	
Distance to Pipeline (miles): 0.7	Pipeline Diameter (inches): 36.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Ohio Power Gavin Plant

Distance to Plant (miles): 10.0

Boiler Capacity (MW): 1,300.0

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Updated: May 1997

Status: Operating

Nelms Cadiz Portal

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: OH

Coalbed: Freeport (L)

County: Harrison

CORPORATE INFORMATION

Current Owner: Harrison Mining Corp.

Parent Company: Harrison Mining Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: Cadiz Portal

MINE ADDRESS

Contact Name: John A. McNab

Phone Number: 614-942-8220

Mailing Address: P.O. Box 176

City: Cadiz

State: OH

ZIP: 43907

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 2.81% - 3.50%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,268

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.2	1.0	1.0	1.1
Estimated Total Methane Liberated (million cf/day):	0.2	0.4	0.4	0.7
Emissions from Ventilation Systems:	0.2	0.4	0.4	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	63	152	153	230

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Nelms Cadiz Portal (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.05	0.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.7%	2.5%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Cincinnati Gas and Electric Co.

Parent Corporation of Utility: Cincinnati Gas and Electric Co.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	8.3	33.4
Mine Electricity Demand:	6.5	26.7
Prep Plant Electricity Demand:	1.9	6.7
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.1	9.3
Assuming 60% Recovery Efficiency: ¹	1.6	13.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas of Ohio Inc.	
Distance to Pipeline (miles): 0.0	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Nelms Cadiz Portal (continued)

Summary of Recent News

The Nelms Cadiz Portal mine is located in Harrison County near Cadiz, Ohio. The mine produces steam coal of around 12,539 btu/ton, and its 1994 production totaled 965,240 tons. Nelms Cadiz Portal is managed by Harrison Mining Corp. of Cadiz, Ohio. As of March 1996, the mine had around 50 million tons in recoverable coal reserves (CO 3/18/96 p.2). The mine had been closed for some time during the 1980s, but reopened in 1990.

The neighboring Nelms No. 1 mine generates electricity using recovered methane. The electricity is transported to and used on-site at the Nelms Cadiz Portal mine.

No further information is available at this time.

Updated: May 1997

Status: Operating

Powhatan No. 4

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: OH

Coalbed: Pittsburgh

County: Monroe

CORPORATE INFORMATION

Current Owner: Quarto Mining

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: J.L. Lyseski, General Superintendent

Phone Number: 614-458-1381

Mailing Address: P.O. Box 231

City: Clarington

State: OH

ZIP: 43915

GENERAL INFORMATION

Number of Employees at Mine: 320

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 3

Sulfur Content of Coal Produced: 3.51% - 4.53%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,500

Depth to Seam (ft): 390

Seam Thickness (ft): 5.3

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.8	3.1	2.7	3.4
Estimated Total Methane Liberated (million cf/day):	1.1	1.4	1.5	1.7
Emissions from Ventilation Systems:	1.1	1.4	1.5	1.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	488	163	201	183

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Powhatan No. 4 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.11	0.17
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.3%	1.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Belmont Electric Cooperative

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	25.4	101.5
Mine Electricity Demand:	19.6	81.2
Prep Plant Electricity Demand:	5.8	20.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	2.6	22.6
Assuming 60% Recovery Efficiency: ¹	3.9	33.8

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.4
Description of Surrounding Terrain: Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 0.1	Pipeline Diameter (inches): 4.0
Owner of Next Nearest Pipeline: Texas Eastern Transmission	
Distance to Next Nearest Pipeline (miles): 1.4	Pipeline Diameter (inches): 30.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Powhatan No. 4 (continued)

Summary of Recent News

The Powhatan No. 4 mine is owned by Quarto Mining, a CONSOL subsidiary. The mine is located in Monroe County, Ohio and produces high-sulfur steam coal. The mine is longwall-equipped.

The Powhatan No. 4 mine was idled on March 31, 1995. CONSOL cited a declining demand for high-sulfur coal and excessive stockpiles as the reason. The idling resulted in 250 workers being laid-off. About 110 workers were retained for day-to-day operational purposes (CW 4/17/95 p.7). The mine resumed production on July 10, 1995.

Sales & Supply

Purchasers of Powhatan No. 4 coal include Cleveland Electric Illuminating, Allegheny Power System and Cincinnati Gas & Electric. In October 1994, Powhatan No. 4 supplied 4.5 million tons of 12,650 Btu/lb coal to Cleveland Electric Illuminating (CW 10/3/94 p.2). Between October and December 1994, the Allegheny Power System bought 125,000 tons per month of coal from Powhatan No. 4 for its Monongahela Power subsidiary (CW 10/10/94 p.6). In late 1995, Cincinnati Gas and Electric awarded a ten year, 1.2 million ton per year coal contract to CONSOL. The coal will be delivered from two Ohio mines, one of which is the Powhatan No. 4 mine (CW 1/2/95 p.3). In March 1996, Powhatan No. 4's high-sulfur coal replaced the low-sulfur coal at Cincinnati Gas and Electric's non-scrubbed units. At the time the SO₂ allowance values were inexpensive so when combined with attractively priced high-sulfur coal the combination provided the best coal purchasing economics (CO 5/13/96 p.1). In mid-1996, Cincinnati Gas & Electric placed spot orders for a total of 898,000 tons of high-sulfur coal. Awards went to the Powhatan No. 4, Powhatan No. 6 and McElroy mines (CO 5/13/96).

Updated: May 1997

Status: Operating

Powhatan No. 6

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: OH

Coalbed: Pittsburgh

County: Monroe

CORPORATE INFORMATION

Current Owner: Ohio Valley Coal Co.

Parent Company: Ohio Valley Resources

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: John R. Forrelli, Mine Superintendant

Phone Number: 412-258-2056

Mailing Address: 56854 Pleasant Ridge Road

City: Alledonia

State: OH

ZIP: 43902

GENERAL INFORMATION

Number of Employees at Mine: 375

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 30

Sulfur Content of Coal Produced: 3.85% - 4.80%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,500

Depth to Seam (ft): 390

Seam Thickness (ft): 5.3

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	4.0	4.5	3.9	4.7
Estimated Total Methane Liberated (million cf/day):	0.9	1.4	1.0	0.4
Emissions from Ventilation Systems:	0.9	1.4	1.0	0.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	83	113	92	31

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Powhatan No. 6 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.03	0.04
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.2%	0.3%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.0%	0.1%

POWER GENERATION POTENTIAL

Utility Electric Supplier: The Dayton Power & Light Co.

Parent Corporation of Utility: DPL Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	35.6	142.2
Mine Electricity Demand:	27.5	113.8
Prep Plant Electricity Demand:	8.1	28.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.6	5.3
Assuming 60% Recovery Efficiency: ¹	0.9	8.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain: Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 0.1	Pipeline Diameter (inches): 4.0
Owner of Next Nearest Pipeline: Texas Eastern Transmission	
Distance to Next Nearest Pipeline (miles): 1.4	Pipeline Diameter (inches): 30.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Powhatan No. 6 (continued)

Summary of Recent News

The Powhatan No. 6 mine is located in Monroe County, Ohio. The mine is owned and operated by Ohio Valley Coal, a subsidiary of Ohio Valley Resources. Powhatan No. 6 produces high-sulfur coal from the Pittsburgh seam and is longwall-equipped. The mine produced about 4.8 million tons in 1996, and with the installation of a new longwall in 1997, it should produce 5.6 million tons in 1997.

On April 17, 1995, Ohio Valley idled the mine as a result of low utility coal burns, a mild winter and a flat spot market for steam coal. The flat market had led to coal stockpiling, triggering a reduction in coal production at Powhatan No. 6 and other high-sulfur producing mines. The idling of the mine was short-lived, however, and within two weeks of being idled it resumed production at an output level of 3 million tons per year. The new output level was approximately a third lower than in 1994, when the mine produced 4.6 million tons. As a result of the uncertain market conditions and the idling of the mine, Ohio Valley announced that it would have to lay-off miners. Initially, the mine laid off 130 workers, but the layoffs were later reduced to 110 workers (CW 5/1/95 p.1).

In early 1997, it was reported that coal operator Robert Murray had purchased some used longwall equipment, to be installed at the Powhatan No. 6 mine in an effort to increase production. The additional output from the Powhatan No. 6 mine would be sold to Cincinnati Gas & Electric and American Electric Power. Although the mine already has a longwall, the second longwall, once installed, would be used when the current longwall is idled for maintenance or is being moved (CO 2/17/97).

Additional capital improvements at the mine include the purchase of a new and rebuilt set of continuous miner units and an upgrade of the mine's prep plant. The mine is planning an \$8 million upgrade of its prep plant. Once completed, the prep plant will be able to handle 2,000 tons per hour of coal, compared to its current capacity of 1,200 tons per hour (CO 2/17/97).

In early 1997, Robert Murray bought 200,000 tons of SO₂ emissions credits to package with his Powhatan No. 6 coal (CO 2/17/97).

Sales & Supply

At present Cleveland Electric Illuminating (CEI) has a contract with Ohio Valley Coal, which states that Ohio Valley will supply 1.2 million tons a year from their Powhatan No. 6 Mine. CEI is currently reconsidering the contract due to the sulfur content of coal produced at the mine. However, a ruling in 1994 by an independent arbitrator stated that CEI cannot end its contract until the expiration date in the fall of 1997 (CO 9/26/94 p.1; CO 2/17/97 p.2).

In early 1997, American Electric Power (AEP) requested that 600,000 tons of Powhatan No. 6 coal be delivered during 1997 and that an additional 1 million tons of coal be delivered from 1998 - 2000 (CO 2/17/97 p.1).

In December 1996, Monongahela Power took 61,466 tons of spot coal for its Pleasants Power Plant in a contract that ran from October 1996 to January 1997. The price in December was \$18.48 per ton (CW 3/11/96 p.8).

In May 1996, Cincinnati Gas & Electric placed spot orders for a total of 898,000 tons of high-sulfur coal. Powhatan No. 6 will provide a portion of this order (5/13/96 p.1).

In 1995, the Allegheny Power System bought 44,280 tons of coal from Powhatan No. 6 for \$20.11 per ton Freight on Board, barge delivered (CW 9/11/95 p.6).

In August 1995, Centerior Energy's East Lake Plant received 65,000 tons of coal from Powhatan No. 6 for a delivered price of \$41.30 per ton (CO 12/4/95 p.3). The following year, the Powhatan No. 6 mine agreed to supply 1.2 million tons per year to Centerior Energy's East Lake and Ashtabula plants. The contract runs through September 1997 (CO 9/24/96 p.1).

6. Profiled Mines (continued)

Pennsylvania Mines

Bailey
Cambria No. 33
Cumberland
Dilworth
Emerald No. 1
Enlow Fork
Grove No. 1
Maple Creek
Mine 84
Tanoma
Urling No. 1
Warwick

Updated: May 1997

Status: Operating

Bailey

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh

County: Greene

CORPORATE INFORMATION

Current Owner: CONSOL Pennsylvania Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: D.M. Yoders, Superintendent

Phone Number: 412-428-1100

Mailing Address: P.O. Box 138

City: Greysville

State: PA

ZIP: 15337

GENERAL INFORMATION

Number of Employees at Mine: 380

Mining Method: Longwall

Year of Initial Production: 1984

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.03% - 2.41%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 800

Seam Thickness (ft): 5.2 - 6.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	6.9	6.6	7.3	7.5
Estimated Total Methane Liberated (million cf/day):	7.3	7.2	8.3	8.2
Emissions from Ventilation Systems:	4.4	4.3	5.0	4.9
Estimated Methane Drained:	2.9	2.9	3.3	3.3
Estimated Specific Emissions (cf/ton):	389	397	415	399

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob

Bailey (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.53	0.79
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.6%	4.0%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.6%	0.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	56.0	223.9
Mine Electricity Demand:	43.3	179.1
Prep Plant Electricity Demand:	12.7	44.8
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	12.4	108.4
Assuming 60% Recovery Efficiency: ¹	18.6	162.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.2
Assuming 60% Recovery Efficiency (Bcf): ¹	1.8
Description of Surrounding Terrain: High Hills/Open High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Carnegie Natural Gas	
Distance to Pipeline (miles): 6.0	Pipeline Diameter (inches): 20.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Hatfield Ferry

Distance to Plant (miles): 24.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Bailey (continued)

Summary of Recent News

The Bailey mine is owned and operated by CONSOL. The mine, which produces steam coal, is located in Greene County, Pennsylvania and mines the Pittsburgh seam.

Bailey, along with its neighboring Enlow Fork mine, are the two flagship CONSOL mines. In 1995, the two mines had a combined production of 15.3 million tons. In 1996, they had a combined production of 16.5 million tons (CO 1/20/97). According to the 1997 Keystone Coal Manual, Bailey was the second most productive underground mine in the U.S. during 1995 producing 7.3 million tons of coal.

Following up on earlier disclosed plans to increase production at the Bailey/Enlow Fork complex, CONSOL recently applied for permission to add acreage to the Bailey mine. The application, which was made to the Pennsylvania Department of Environmental Protection, covers 11,000 acres to be added to the permitted mining area and 4,100 additional acres in the subsidence control area (CO 1/20/97). However, CONSOL is in discussions, with Texas Eastern Transmission Corporation (Texas Eastern), to resolve some technical issues. Texas Eastern has gas lines and compressor stations located over the proposed mining area, and they are concerned that longwall subsidence will hurt those facilities (CO 5/19/97). Despite these discussions, all of this activity indicates that CONSOL is planning to expand production from its Bailey mine. CONSOL plans to increase production from the Bailey/Enlow Fork mine complex to approximately 20 million tons annually by the end of 1998 (CO 5/20/96; CO 11/11/96).

By mid-1997, coal produced at the Bailey mine should have another route through which it can be shipped. CONSOL decided to construct the Alicia transloading dock on the Monongahela River, following a delay of more than a year. The project had been slated to begin in 1994, but had been postponed due to American Electric Power's decision not to buy coal being shipped via the Monongahela River for its Kammer plant. The dock will move coal rail-to-river and have a throughput capacity of up to 5 million tons annually. Construction began in the spring of 1996 and the dock should be operational by the spring of 1997 (CO 8/4/1996). Sources have speculated that the construction of the Alicia dock signals that CONSOL is interested in handling transloading itself rather than outsourcing that duty (CO 4/8/96).

The Bailey mine is not unionized. Union sources have long stated that the UMW's major organizing targets include CONSOL's Enlow Fork and Bailey mines. At a national UMW meeting in Miami in 1995, delegates considered changes to the union's selective strike fund. The fund, which is currently used to support selective strikes, would be used to organize non-union coal mines (CO 9/25/96). The outcome of that discussion is unknown.

Sales & Supply

Purchasers of Bailey coal include international steam coal buyers and domestic utilities. Those buyers range from Brazilian and Japanese steel mills to domestic utilities that use medium-sulfur coal.

In 1996, CONSOL agreed to ship Brazilian steel mills 150,000 tons of Bailey coal. The coal was destined for the CST mill and the Cospia mill (CW 5/13/96). Bailey also supplies coal to Japanese and European steel makers (CW 2/5/96).

In early 1996, Detroit Edison purchased 100,000 tons of coal from CONSOL's Bailey/Enlow Fork operation. The coal was delivered from March through December 1996 to the utility's Monroe and Trenton Channel power plants (CW 4/1/96). A year earlier in April 1995, the utility bought 24,000 tons of spot coal from the Bailey mine (CW 4/3/95).

Wisconsin Electric & Power burns contract coal supplied by CONSOL out of its Bailey operation. Valley burns about 600,000 tons per year and Port Washington burns 300,000 - 500,000 tons per year (CW 2/19/96).

Rochester Gas & Electric purchased 10,000 tons of spot coal from the Bailey mine in 1995. The coal was delivered via Conrail in November 1995 (CW 1/8/96).

Bailey (continued)

New York State Electric & Gas power plants will receive 288,000 tons of coal in November 1995, including 244,000 tons of CONSOL contract coal. Of the CONSOL tonnage, the Milliken plant will receive 72,000 tons of Bailey coal (CW 10/30/95). New York State Electric & Gas power plants will receive 262,000 tons of coal in August 1995, including 45,000 tons of coal from CONSOL's Blacksville and Bailey mines (CW 8/7/95).

Updated: May 1997

Status: Closed

Cambria No. 33

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Kittaning (U&L)

County: Cambria

CORPORATE INFORMATION

Current Owner: BethEnergy Mines Inc.

Parent Company: Bethlehem Steel Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: Cambria Slope No.33

MINE ADDRESS

Contact Name: NA

Phone Number: 814-472-4691

Mailing Address: 17 Johns Street

City: Johnstown

State: PA

ZIP: 15907

GENERAL INFORMATION

Number of Employees at Mine: 398 ¹

Mining Method: Longwall

Year of Initial Production: 1964

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 0.71% - 2.05%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,300

Depth to Seam (ft): NA

Seam Thickness (ft): 3.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.3	0.6	0.0	0.0
Estimated Total Methane Liberated (million cf/day):	18.0	9.5	14.2	0.0
Emissions from Ventilation Systems:	10.8	5.7	8.5	0.0
Estimated Methane Drained:	7.2	3.8	5.7	0.0
Estimated Specific Emissions (cf/ton):	5,161	5,570	0	0

Estimated Current Drainage Efficiency: Mine closed; not applicable

Drainage System Used: Vertical Gob, Horizontal Pre-Mine (Mine closed; drainage system not active)

¹ Number of employees based on when mine was in operation.

Cambria No. 33 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency	
(Based on 1994 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.62	0.92
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	39.5%	59.3%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	9.1%	13.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Pennsylvania Electric Co.

Parent Corporation of Utility: General Public Utilities Corp.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1994 data):	4.7	18.7
Mine Electricity Demand:	3.6	14.9
Prep Plant Electricity Demand:	1.1	3.7
Potential Generating Capacity (1994 data)		
Assuming 40% Recovery Efficiency:	14.4	126.1
Assuming 60% Recovery Efficiency:	21.6	189.1

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1994 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf):	1.4
Assuming 60% Recovery Efficiency (Bcf):	2.1
Description of Surrounding Terrain:	Open High Hills/Low Mountains
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Texas Eastern Transmission
Distance to Pipeline (miles):	3.3
Pipeline Diameter (inches):	20.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: NA

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Fertilizers, chemicals, and steel production; hospitals and other municipal buildings.

Cambria No. 33 (continued)

Summary of Recent News

Cambria No. 33 began coal production in 1964. The first of four longwalls started operating in March 1968. Owned by Beth Energy mining, Cambria produced primarily coking coal for Bethlehem Steel (CW 9/9/91). Beset by production problems and high costs, Cambria permanently shut down in August 1994.

Updated: May 1997

Status: Operating

Cumberland

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh

County: Greene

CORPORATE INFORMATION

Current Owner: PA Services Corp., Cyprus Cumberland Resources

Parent Company: Cyprus Amax

Previous Owner(s): U.S. Steel Mining Co., Inc.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: C.E. Zabrosky, Mine Superintendent

Phone Number: 412-223-5400

Mailing Address: P.O. Box 711

City: Waynesburg

State: PA

ZIP: 15370

GENERAL INFORMATION

Number of Employees at Mine: 400

Mining Method: Longwall

Year of Initial Production: 1972

Primary Coal Use: Steam

Mine Life Expectancy (years): 26

Sulfur Content of Coal Produced: 1.59% - 2.62%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 14,039

Depth to Seam (ft): 900

Seam Thickness (ft): 6.5 - 7.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.4	4.0	3.8	5.2
Estimated Total Methane Liberated (million cf/day):	6.2	6.4	9.3	10.9
Emissions from Ventilation Systems:	5.3	5.4	7.9	9.3
Estimated Methane Drained:	0.9	1.0	1.4	1.6
Estimated Specific Emissions (cf/ton):	954	581	900	768

Estimated Current Drainage Efficiency: 15%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Cumberland (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.71	1.06
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	4.8%	7.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.1%	1.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	39.0	156.0
Mine Electricity Demand:	30.2	124.8
Prep Plant Electricity Demand:	8.9	31.2
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	16.6	145.2
Assuming 60% Recovery Efficiency: ¹	24.9	217.8

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.6
Assuming 60% Recovery Efficiency (Bcf): ¹	2.4
Description of Surrounding Terrain: High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Texas Eastern Transmission	
Distance to Pipeline (miles): 0.1	Pipeline Diameter (inches): 24.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Hatfield Ferry

Distance to Plant (miles): 14.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

¹ Drainage system already in use; current drainage efficiency shown on previous page.

Cumberland (continued)

Summary of Recent News

The Cumberland mine, located in Greene County, Pennsylvania, was developed in the 1970s with a partial capital investment by Ontario Hydro. However, Ontario Hydro ceased buying coal from the mine in the late 1980s due to Canadian clean air laws (CO 2/1/93 p. 5). In June 1993, U.S. Steel Mining Co. (USM) sold the mine and its end-user contracts to Cyprus Amax Coal Co. (Cyprus Amax), a Cyprus Amax Minerals Co. subsidiary that has become the second largest coal producer in the United States. Cyprus Amax also acquired USM's short-line railroad used to ship Cumberland coal to the Monongahela River (CO 6/14/93 p. 4, Keystone 1997). The Cumberland mine is adjacent to Cyprus Amax's Emerald No. 1 mine. Both mines operate in the Pittsburgh No. 8 seam, and the company manages both mines through the same business unit. United Mine Workers of America represents workers at both mines. Cumberland's management reached an agreement with union workers to implement an "alternative schedule" system that enables the mine to employ four crews and operate seven days per week (Coal 12/96 p. 39-40). Coal from the Cumberland mine averages 13,032 Btu/lb and has a sulfur content of 2.14 percent and an ash content of 8.48 percent (Keystone 1997).

The Cumberland mine operates some of the largest longwall panels in the country (Coal 12/96 p. 40). In October 1994, the mine installed a new \$20.4 million longwall mining system which lowered unit costs by 14 percent (WC 8/95 p. 4, CO 2/6/95 p. 1). The company also upgraded the mine's coal haulage systems and preparation plant, and currently operates full-face continuous miners (CO 4/10/95 p. 1, Coal 12/96 p. 40). In June 1995, the mine set a new world record for monthly longwall production of 573,000 tons of washed coal (Coal 8/95 p. 9, WC 8/95, p. 4). Other mines have since surpassed that record (CO 12/11/95 p. 1, Coal 12/96 p. 30).

By acquiring reserves owned by the Emerald mine, the Cumberland mine extended its lifetime, predicted to end by the year 2000, by an additional 20 years (CO 2/1/93 p. 5, Coal 12/96). The Cumberland mine plans to seal its current workings once it completes the sinking of a new shaft, No. 6, in 1997 (Coal 12/96 p. 40). The company expects the Cumberland mine to increase its annual coal production from an estimated 5.2 million tons in 1996 to 7 million tons by 1999 (Coal 12/96 pp. 22, 39).

In July 1996, Cyprus Amax acquired from CNG Coal Co. 200 million tons of coal reserves adjacent to both the Emerald and Cumberland mines (CW 7/29/96 p. 3). However, these reserves are not mineable from either existing operation. The company has not announced whether it will extend the operations of the Cumberland and/or Emerald mines into the acquired tract or open a new mine (CO 5/20/96 p. 1, CO 7/29/96 p. 3, CW 7/29/96 p. 3).

In addition to a gob well degasification program, the Cyprus-Amax Cumberland mine has drilled two vertical pre-mine wells to date. Production from the vertical wells ranges from 60,000 to 149,000 cubic feet per day. The vertical wells are currently being converted to gob wells. Cumberland has also drilled five horizontal pre-mine wells to date, with a typical length of 4,500 feet.

Cumberland plans to continue its vertical and horizontal pilot well program, as it is proving effective in reducing methane build-up in the mine. Tracking of methane delay times has shown that there are fewer methane-related delays in mining areas that had previously been degasified.

Sales & Supply

As of December 1996, the Cumberland mine supplied steam coal to about 30 predominantly domestic customers, including the Tennessee Valley Authority (TVA), Duquesne Light, Public Service of Indiana, and Ohio Edison (Coal 12/96 p. 40). In November 1994, TVA awarded a six-year contract to the Cumberland mine and/or Emerald mine for 860,000 tons per year (CW 11/14/94 p. 1; CO 11/14/94 p. 1). TVA made this purchase under its Requisition 30 for high-sulfur coal (CO 11/14/94 p. 1).

In October 1995, the Cumberland mine together with Cyprus Amax's Cannelton operations began supplying 30,000 tons per month under a one-year contract with Big Rivers Electric's Coleman plant (CO 9/18/95 p. 7). In December 1995, the Cumberland mine and Cannelton operations received an additional spot order for 90,000 tons of coal for the Coleman plant (CO 12/18/95 p. 5).

Cumberland (continued)

In 1996, the Cumberland mine shipped 250,000 tons of coal to Archer Daniels Midland for its Clinton 1A plant (CW 2/26/96 p. 8).

In July 1996, Cincinnati Gas & Electric awarded a four-year contract, to be followed by two three-year options, jointly to the Cumberland mine and the Cannelton operations for 1 million tons of coal per year (CO 7/29/96 p. 7).

In 1997, Ohio Edison contracted with the Cumberland mine for 800,000 tons of coal (CO 1/13/97 p. 7).

Updated: May 1997

Status: Operating

Dilworth

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh

County: Greene

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): USX

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: L. Barietta, General Superintendent

Phone Number: 412-966-5065

Mailing Address: 450 Racetrack Road

City: Washington

State: PA

ZIP: 15301

GENERAL INFORMATION

Number of Employees at Mine: 361

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.50%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 650

Seam Thickness (ft): 6.3 - 6.6

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.2	2.7	3.0	4.8
Estimated Total Methane Liberated (million cf/day):	1.8	2.2	3.3	4.2
Emissions from Ventilation Systems:	1.1	1.3	2.0	2.5
Estimated Methane Drained:	0.7	0.9	1.3	1.7
Estimated Specific Emissions (cf/ton):	569	288	409	314

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob

Dilworth (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.27	0.41
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.1%	3.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.5%	0.7%

POWER GENERATION POTENTIAL

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	28.1	116.2
Mine Electricity Demand:	28.1	116.2
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	6.3	55.3
Assuming 60% Recovery Efficiency: ¹	9.5	83.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.6
Assuming 60% Recovery Efficiency (Bcf): ¹	0.9
Description of Surrounding Terrain: High Hills/Open High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Texas Eastern Transmission	
Distance to Pipeline (miles): 1.0	Pipeline Diameter (inches): 20.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Mitchell

Distance to Plant (miles): 12.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Dilworth (continued)

Summary of Recent News

Dilworth is owned and operated by Consolidation Coal Company, a wholly owned subsidiary of CONSOL. USX Corporation sold Dilworth to CONSOL in 1983. The mine produces both metallurgical and steam grade coal. The mine is a medium-sulfur coal producer.

As a result of the two types of coal that Dilworth produces, the mine is capable of supplying both export metallurgical markets and domestic utilities. In April 1996, Kobe Steel Company, a long term buyer of Dilworth coal, chose to buy 90,00 tons of Alpine mine coal instead, thereby replacing Dilworth coal for that year. Some Japanese mills, including Kobe steel, use petroleum coke in their furnaces along with metallurgical coke produced from coal, so they are not solely dependent on metallurgical coal. The action that Kobe Steel took is becoming increasingly common among Japanese steel companies and causes alarm to medium-sulfur metallurgical coal producers like Dilworth. Increasingly, Japanese steel companies are buying higher-sulfur petcoke because they are cheaper and then they are mixing the higher-sulfur petcoke with lower sulfur coals to lower the overall sulfur content of the coal they burn, thereby negating the need for medium-sulfur coals (CW 5/6/96).

Sales & Supply

Purchasers of Dilworth coal include domestic and international steel makers and domestic utilities. One of Dilworth's largest domestic industrial clients is National Steel (CO 12/19/94). Dilworth also supplies Kobe Steel of Japan (CW 5/6/96).

One of Dilworth's largest domestic utility clients is the Allegheny Power System. From April to July 1996, Dilworth supplied about 33,000 tons of coal per month (CW 9/16/96). Dilworth shipped 28,040 tons of coal in December 1995 to the Allegheny Power System's Willow Island plant under a four month award, which began in October 1995 (CW 3/11/96).

Another of Dilworth's customers is the Tennessee Valley Authority (TVA). From October through December 1994, TVA bought 70,000 tons of coal (CW 5/15/95).

Updated: May 1997

Status: Operating

Emerald No. 1

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh

County: Greene

CORPORATE INFORMATION

Current Owner: PA Services Corp., Cyprus Emerald Resources

Parent Company: Cyprus Amax

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: D.P. Brown, Vice President

Phone Number: 412-627-7500

Mailing Address: P.O. Box 371

City: Waynesburg

State: PA

ZIP: 15370

GENERAL INFORMATION

Number of Employees at Mine: 474

Mining Method: Longwall

Year of Initial Production: 1977

Primary Coal Use: Steam

Mine Life Expectancy (years): 10

Sulfur Content of Coal Produced: 0.83% - 3.65%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 1,000

Seam Thickness (ft): 6.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	3.2	3.4	3.8	3.2
Estimated Total Methane Liberated (million cf/day):	6.0	9.8	10.0	9.7
Emissions from Ventilation Systems:	3.6	5.9	6.0	5.8
Estimated Methane Drained:	2.4	3.9	4.0	3.9
Estimated Specific Emissions (cf/ton):	684	1,047	969	1,092

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Emerald No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.63	0.94
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	7.2%	10.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.7%	2.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	24.2	96.9
Mine Electricity Demand:	18.7	77.5
Prep Plant Electricity Demand:	5.5	19.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	14.6	128.3
Assuming 60% Recovery Efficiency: ¹	22.0	192.5

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.4
Assuming 60% Recovery Efficiency (Bcf): ¹	2.1
Description of Surrounding Terrain: High Hills/Open High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Texas Eastern Transmission	
Distance to Pipeline (miles): 0.1	Pipeline Diameter (inches): 24.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Hatfield Ferry

Distance to Plant (miles): 14.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Emerald No. 1 (continued)

Summary of Recent News

The Emerald No. 1 mine, located in Greene County, Pennsylvania, is owned by Cyprus Amax Coal Co., a Cyprus Amax Minerals Co. subsidiary that has become the second largest coal producer in the United States (Keystone 1997). The Emerald mine is adjacent to Cyprus Amax's Cumberland mine. Both mines operate in the Pittsburgh No. 8 seam, and the company manages both mines through the same business unit. United Mine Workers of America represents workers at both mines (Coal 12/96 p. 39-40). Coal from the Emerald mine averages 13,179 Btu/lb and has a sulfur content of 1.53 percent and ash content of 7.55 percent (Keystone 1997).

Like Cumberland, Emerald operates a longwall mining system and uses full-face continuous miners for panel development. The company invested \$7 million in a new slope belt and raw coal handling facility (Coal 12/96 p. 41). The company expects the Emerald mine to increase its annual coal production from an estimated 3.4 million tons in 1996 to 7 million tons by 1999 (Coal 12/96 pp. 22, 39). In 1995, the company reported that it planned to install a new longwall system in the Emerald mine in 1997 (CO 4/10/95 p. 1).

In the spring of 1996, Emerald's longwall mining operation was delayed when it encountered a 300-350 foot sandstone channel that forced the operation to shift to a new location (CO 6/3/96 p. 7, CO 6/29/96 p. 2, Coal 12/96 p. 40). In September 1996, roof stress and a roof fall in the tailgate section further delayed production; the mine reported no associated injuries (CO 9/23/96 p. 1). In the fourth quarter of 1996, the company reported record earnings from its Pennsylvania operations, a strong indication that the geological problems at the Emerald mine had been resolved (CO 1/27/97 p. 1).

In early 1997, Cyprus Amax reported that it expects Emerald's reserves to last for about ten more years. One factor that may impact the life expectancy of the mine is new state regulations regarding the permitting of valley fills used to dispose of waste material from underground mines. Emerald's existing valley fill may be suitable for continued use for four to six years. The company has applied to expand the valley fill to accommodate the mine's production of waste material for an additional four years (CO 3/3/97 p. 2).

The future of the Emerald mining operations may extend beyond ten years. Cyprus Amax has investigated expanding its mining operations into the company's Upper Freeport seam reserves, which are adjacent to the Emerald mine and could contain up to 170 million tons of compliance coal (CO 5/20/96 p. 8, Coal 12/96 p. 39). The company could either move its Emerald mining operations from the Pittsburgh seam to the Upper Freeport seam, or open a new mine to access the Upper Freeport seam. Coal from the Upper Freeport seam could offer a lower-sulfur alternative to Emerald coal, the sulfur content of which may increase from the current level of 2.5 lbs/mmBtu to 3.5-4.0 lbs/mmBtu toward the end of the century (CO 11/11/96 pp. 1-2).

In July 1996, Cyprus Amax acquired from CNG Coal Co. 200 million tons of coal reserves adjacent to both the Emerald and Cumberland mines (CW 7/29/96 p. 3). However, these reserves are not mineable from either existing operation. The company has not announced whether it will extend the operations of the Cumberland and/or Emerald mines into the acquired tract or open a new mine (CO 5/20/96 p. 1, CO 7/29/96 p. 3, CW 7/29/96 p. 3).

Sales & Supply

Emerald produces both steam and metallurgical coal (Keystone 1997). The mine has a term contract to supply 500,000 tons of coal per year to the 153-MW Taunton cogeneration facility in Massachusetts; however, the future of that facility may be in question due to environmental opposition and a lack of customers for the facility's electricity (CO 1/9/95 pp. 3-4).

The mine holds a joint contract with CONSOL's Bailey mine to supply Northeast Utilities with a combined total of 800,000 tons of coal per year over a multiple-year period. The Emerald mine also supplies about one-third of an additional 400,000 ton-per-year contract with Northeast Utilities (CW 10/3/94 p. 3).

Emerald No. 1 (continued)

In November 1994, the Tennessee Valley Authority (TVA) awarded a six-year contract to the Cumberland mine and/or Emerald mine for 860,000 tons per year (CW 11/14/94 p. 1; CO 11/14/94 p. 1). TVA made this purchase under its Requisition 30 for high-sulfur coal (CO 11/14/94 p. 1).

In 1995, the Emerald mine supplied 48,000 tons of coal to Detroit Edison (CO 8/7/95 p. 7).

Ontario Hydro ordered 190,000 tons from the Emerald mine in 1997 (CO 2/3/97 p. 7).

Emerald's other spot and contract coal customers have included the Keystone Conemaugh Projects Office (CO 11/27/95 pp. 1, 8), Cleveland Electric Illuminating (CO 12/4/95 pp. 2-3), and Rochester Gas & Electric (CW 1/8/96 p. 7).

Updated: May 1997

Status: Operating

Enlow Fork

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh

County: Greene

CORPORATE INFORMATION

Current Owner: Enlow Fork Mining Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Paul Kvederis, Manager Public Relations

Phone Number: 412-663-7501

Mailing Address: 322 Enon Church Road

City: West Finley

State: PA

ZIP: 15377

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Longwall

Year of Initial Production: 1990

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.00% - 2.41%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,000

Depth to Seam (ft): 800

Seam Thickness (ft): 5.7 - 6.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	7.4	8.1	8.0	8.7
Estimated Total Methane Liberated (million cf/day):	9.8	9.8	11.7	14.3
Emissions from Ventilation Systems:	5.9	5.9	7.0	8.6
Estimated Methane Drained:	3.9	3.9	4.7	5.7
Estimated Specific Emissions (cf/ton):	483	443	530	600

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob

Enlow Fork (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.93	1.40
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	4.0%	6.0%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.9%	1.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	65.4	261.7
Mine Electricity Demand:	50.6	209.4
Prep Plant Electricity Demand:	14.9	52.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	21.7	190.2
Assuming 60% Recovery Efficiency: ¹	32.6	285.4

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	2.1
Assuming 60% Recovery Efficiency (Bcf): ¹	3.1
Description of Surrounding Terrain:	Open Hills/Open High Hills
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Carnegie Natural Gas
Distance to Pipeline (miles):	6.0
Pipeline Diameter (inches):	20.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Mitchell/Hatfield Ferry

Distance to Plant (miles): 29.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Enlow Fork (continued)

Summary of Recent News

The Enlow Fork mine is owned and operated by Enlow Fork Mining Company, a wholly owned subsidiary of CONSOL. The mine was opened in 1990 and produces steam coal. The mine is located in Greene County, Pennsylvania and mines the Pittsburgh seam.

Enlow Fork, along with the neighboring Bailey mine, are the two flagship CONSOL mines. In 1995, the two mines had a combined production of 15.3 million tons. In 1996, they had a combined production of 16.5 million tons (CO 1/20/97). According to the 1997 Keystone Coal Manual, Enlow Fork was the top producing underground mine in the U.S. during 1995, producing 8.0 million tons of coal.

CONSOL plans to further increase production from the Bailey/Enlow Fork mine complex to approximately 20 million tons annually by the end of 1998 (CO 5/20/96; CO 11/11/96). At the end of 1996, the mines were operating at capacity so additional capacity is needed if production is to be further increased. Early indications, from CONSOL, are that budget approval for capital expenditures related to this planned increase in production will not be a problem (CO 11/11/96).

By mid-1997, coal produced at the Enlow Fork mine should have another route through which it can be shipped. CONSOL decided to construct the Alicia transloading dock on the Monongahela River, following a delay of more than a year. The project had been slated to begin in 1994, but had been postponed due to American Electric Power's decision not to buy coal being shipped via the Monongahela River for its Kammer plant. The dock will move coal rail-to-river and have a throughput capacity of up to 5 million tons annually. Construction began in the spring of 1996 and the dock should be operational by the spring of 1997 (CO 8/4/1996). Sources have speculated that the construction of the Alicia dock signals that CONSOL is interested in handling transloading itself rather than outsourcing that duty (CO 4/8/96).

The Enlow Fork mine is not unionized. Union sources have long stated that the UMW's major organizing targets include CONSOL's Enlow Fork and Bailey mines. At a national UMW meeting in Miami in 1995, delegates considered changes to the union's selective strike fund. The fund, which is currently used to support selective strikes, would be used to organize non-union coal mines (CO 9/25/96). The outcome of that discussion is unknown.

Sales & Supply

Detroit Edison has purchased 100,000 tons of coal from CONSOL's Bailey/Enlow Fork operation. The coal is for delivery from March through December 1996 (CW 4/1/96).

Enlow Fork also supplies coal to American Electric Power (AEP).

Updated: May 1997

Status: Operating

Grove No. 1

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Kittaning (U)

County: Somerset

CORPORATE INFORMATION

Current Owner: Lion Mining Co.

Parent Company: Lion Mining Co.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Gary Bieniasz, Mine Superintendent

Phone Number: 814-629-6687

Mailing Address: P.O. Box 209

City: Jennerstown

State: PA

ZIP: 15547

GENERAL INFORMATION

Number of Employees at Mine: 75

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.50%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 12,500

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.5	0.5	0.6	0.5
Estimated Total Methane Liberated (million cf/day):	0.6	0.5	0.1	0.1
Emissions from Ventilation Systems:	0.6	0.5	0.1	0.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	446	354	64	78

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Grove No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.01	0.01
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.5%	0.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Pennsylvania Electric Co.

Parent Corporation of Utility: General Public Utilities Corp.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	2.7	11.2
Mine Electricity Demand:	2.7	11.2
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.2	1.3
Assuming 60% Recovery Efficiency: ¹	0.2	2.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.0
Assuming 60% Recovery Efficiency (Bcf): ¹	0.0
Description of Surrounding Terrain: Open High Hills/Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Peoples Natural Gas	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): 14.0
Owner of Next Nearest Pipeline: Texas Eastern Transmission	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): 24.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Grove No. 1 (continued)

Summary of Recent News

The Grove No. 1 mine is a room-and-pillar operation located in Somerset County near Jennerstown, Pennsylvania. Grove produces steam and metallurgical coal with a sulfur content of around 1.50%. The mine is operated by Lion Mining Co. out of Johnston, PA, and employs 75 workers (1997 Keystone Coal Industry Manual).

Sales & Supply

Pennsylvania Electric purchased around 16,000 tons per month of spot coal from Grove No. 1 and the Jennifer mine (also in Somerset County) in late 1994, as part of a one year supply agreement for its Homer City power plant (CW 12/19/94 p.4).

In late 1995, Rochester & Pittsburgh Coal (R&P) closed three of its highest cost mines and began purchasing replacement coal from other producers to supply its Keystone power plant. The Grove mine was one operation suspected as a potential supplier to R&P, possibly for a one-year contract for around 15,000 tons per month (CO 1/8/96 p.2).

Updated: May 1997

Status: Operating

Maple Creek

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh

County: Washington

CORPORATE INFORMATION

Current Owner: Maple Creek Mining Inc.

Parent Company: Maple Creek Mining Inc.

Previous Owner(s): U.S. Steel Mining Co., Inc.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: W.K. Schlaupitz, Mine Superintendent

Phone Number: 412-223-5400

Mailing Address: R.D. 2, Box 599

City: Eighty Four

State: PA

ZIP: 15330

GENERAL INFORMATION

Number of Employees at Mine: 340

Mining Method: Longwall

Year of Initial Production: 1921

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.16% - 2.10%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,300

Depth to Seam (ft): 425

Seam Thickness (ft): 5.3

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	0.022	0.9	3.4
Estimated Total Methane Liberated (million cf/day):	0.9	0.5	0.5	0.7
Emissions from Ventilation Systems:	0.9	0.5	0.5	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	190	8,450	201	75

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Maple Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.05	0.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.5%	0.7%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	25.5	102.1
Mine Electricity Demand:	19.7	81.6
Prep Plant Electricity Demand:	5.8	20.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.1	9.3
Assuming 60% Recovery Efficiency: ¹	1.6	13.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Open High Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 2.0	Pipeline Diameter (inches): 24.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Steel, plastics, apparel, glass, fertilizers, and other types of manufacturing; municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Maple Creek (continued)

Summary of Recent News

Located in Washington County, Ohio, the Maple Creek mine produces a high-volatile, mid-sulfur coal from the Pittsburgh seam. The mine is owned and operated by Maple Creek Mining, Inc. The mine had been previously owned by U.S. Steel Mining, Inc., a wholly owned subsidiary of the USX Corporation.

U.S. Steel Mining, Inc. closed the mine in 1994, citing high mining costs as the reason (USX Corporation 10-K Report). Following the closure of the mine the state of Pennsylvania, with the assistance of the UMW, actively sought buyers for the mine by providing financial incentives. The state had been concerned about the number of jobs that would be lost. A number of major coal companies showed some interest in buying Maple Creek, including Drummond Coal. However, in late 1994 Drummond Coal decided against purchasing the mine, citing cash flow as the problem. With Drummond's withdrawal, the only viable buyer remaining was coal operator Robert Murray (CO 9/26/94). In December 1994, Robert Murray signed a letter of intent to purchase the idle Maple Creek mine and preparation plant. Robert Murray formed a new company called Maple Creek Mining, Inc., as a holding company for the mine. Maple Creek Mining, Inc.'s purchase of the mine was finalized in mid-1995 (CO 1/16/95).

After purchasing the mine, Murray renovated the mine by retiring an existing longwall and replacing it with a newer longwall, removing rail tracks and replacing them with belt haulage lines, and replacing and upgrading the mine's continuous miner units. The mine was reopened in July 1995 with production beginning in September 1995 (CO 7/17/95; CO 7/3/95; CO 8/14/95).

In early 1997, it was reported that Robert Murray had bought used longwall equipment. Some of the equipment purchased was to be installed at the Powhatan No. 6 mine with the remaining equipment to be installed at the Maple Creek mine as pre-set equipment for when a longwall is to be moved. With this equipment the mine should become more efficient because the time it takes to move a longwall would be reduced (CO 2/17/97).

Additional capital improvements at the mine included the recently completed upgrade of the mine's prep plant. Maple Creek Mining, Inc. spent about \$3 million on the upgrade. A \$4 million plant upgrade is expected to occur during 1997. In July 1997, Maple Creek Mining, Inc. plans to install a new drift, called New Eagle, which will have its entry next to the Maple Creek entry. This drift, which will use one continuous miner unit, will produce lower-sulfur coal that will be blended with Maple Creek coal (CO 2/17/97).

Sales & Supply

As part of the purchase deal, U.S. Steel Mining, Inc. (USM) agreed to a seven-year, 1 million tons per year take-back contract for Maple Creek coal. The coal will be delivered to USM's Clairton coke works. Other potential purchasers of Maple Creek coal include Shenango Steel and American Metals & Coke International (CO 7/17/97).

Other purchasers of Maple Creek coal include Duquesne Light and Ohio Valley Coal. These purchasers buy Maple Creek coal for blending purposes (CO 9/25/95).

Updated: May 1997

Status: Operating

Mine 84

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh

County: Washington

CORPORATE INFORMATION

Current Owner: Eighty Four Mining Co.

Parent Company: Rochester and Pittsburgh Coal Co.

Previous Owner(s): Beth Energy Mines Inc.

Previous or Alternate Name of Mine: Ellsworth or Livingston

MINE ADDRESS

Contact Name: M.E. Jones, General Superintendent

Phone Number: 412-223-6218

Mailing Address: P.O. Box 143

City: Eighty Four

State: PA

ZIP: 15330

GENERAL INFORMATION

Number of Employees at Mine: 470

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.33% - 1.76%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,100

Depth to Seam (ft): 625

Seam Thickness (ft): 7.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.1	0.3	1.3	3.0
Estimated Total Methane Liberated (million cf/day):	1.8	1.5	2.5	4.1
Emissions from Ventilation Systems:	1.8	1.5	2.5	4.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	8,874	1,897	679	495

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Mine 84 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.27	0.40
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.3%	4.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.8%	1.1%

POWER GENERATION POTENTIAL

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	22.7	90.8
Mine Electricity Demand:	17.5	72.6
Prep Plant Electricity Demand:	5.2	18.2
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	6.2	54.4
Assuming 60% Recovery Efficiency: ¹	9.3	81.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.6
Assuming 60% Recovery Efficiency (Bcf): ¹	0.9
Description of Surrounding Terrain: Open High Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas of Pennsylvania, Inc.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Mitchell

Distance to Plant (miles): 9.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Steel, plastics, apparel, glass, fertilizers, and other types of manufacturing; municipal buildings.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Mine 84 (continued)

Summary of Recent News

Rochester and Pittsburgh (R&P) acquired Mine 84 from BethEnergy, a subsidiary of Bethlehem Steel in 1992. R&P shut the mine soon after the purchase to refurbish it, including installation of a 72-inch-wide main beltline, which replaced the mine's old rail haulage system and increased capacity. A ventilating shaft and a new portal along with above-ground storage and unit-train loadout facilities were also installed. The mine came back into production with continuous miners in April 1994 (CO 10/2/95). R&P planned to open the first longwall in the third quarter of 1995 and a second longwall panel was to open in 1997 bringing production up to around 7 million tons of coal per year. The coal from Mine 84 averages 1.3 percent sulfur, 6.5 percent ash, and 13,000 Btu/lb., which makes it attractive to utilities trying to meet the Phase-1 requirements under the Clean Air Act of 1990. In April 1995, the company had eight utilities committed to purchase coal from Mine 84.

The first of two longwalls began operation, as scheduled, in September 1995 and performed well in completing its first two panels. In late 1995 and early 1996, the continuous miners fell behind schedule for developing new panels due to geological problems with the roof and rapid expansion of the mine. These problems resulted in R&P almost defaulting on certain obligations related to Mine 84 financing (CO 4/22/95). In August 1996, R&P had to raise \$25 million in additional capital investment to continue the longwall mining (CO 8/19/96). A R&P third quarter 10Q Report issued November 14, 1996, stated that the company may have to take a writedown on the investment in Mine 84. The geology problems (mostly due to a bad roof) have kept Mine 84's continuous miner units from developing new longwall panels on schedule. R&P hired a consulting firm to study the mine's problems and delayed the installation of a second longwall (scheduled to be in place in 1997) for an unspecified period of time (CO 11/18/96). In the December 9, 1996 issue of Coal Outlook, the magazine reported that "rumors abound that Mine 84 might be for sale."

In addition to the problems with the longwall, R&P has encountered difficulties in keeping its environmental permits. In 1995, the Pennsylvania Department of Environmental Resources issued a permit revision to R&P that allowed the company to expand the subsidence-control area for its longwall mining at Mine 84 (CO 10/10/95). The revised permit allowed the company to expand production at the mine beyond pre-existing levels. Columbia Gas of Pennsylvania, local water companies and a citizens group called People United to Save Homes, appealed to the Department of Environmental Resource's Environmental Hearing Board, because they were concerned that expanded mining could harm gas and water lines, and homes in the area. On November 27, 1996, the Environmental Hearing Board issued a ruling that R&P cannot mine under the water line until the company submits a revised mining plan that shows subsidence will not hurt the water line, or until it can work out an agreement with the water company. R&P worked out a confidential settlement with Columbia Gas. On December 10, 1996, the Environmental Hearing Board began a series of hearings to address further arguments in the case (CO 12/9/96). R&P settled with Pennsylvania American Water Company on January 3, 1997, after stopping work on the longwall panel for four weeks (CO 1/13/97).

Updated: May 1997

Status: Operating

Tanoma

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Kittaning (L)

County: Indiana

CORPORATE INFORMATION

Current Owner: Tanoma Mining Co., Inc.

Parent Company: American Metals & Coal International, Inc. (AMCI)

Previous Owner(s): None

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Marvin Phillips, Mine Superintendent

Phone Number: 412-349-8833

Mailing Address: R.D. #1, Box 594

City: Marion Center

State: PA

ZIP: 15759

GENERAL INFORMATION

Number of Employees at Mine: 196

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 21

Sulfur Content of Coal Produced: 0.85%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,800

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.5	0.5	0.5	0.6
Estimated Total Methane Liberated (million cf/day):	0.5	0.7	0.9	0.9
Emissions from Ventilation Systems:	0.5	0.7	0.9	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	345	492	638	589

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Tanoma (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.09
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.7%	5.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.9%	1.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Duquesne Light Co.

Parent Corporation of Utility: DQE

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	4.2	16.7
Mine Electricity Demand:	3.2	13.4
Prep Plant Electricity Demand:	1.0	3.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.4	11.9
Assuming 60% Recovery Efficiency: ¹	2.0	17.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Open High Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: T.W. Phillips Gas & Oil Co.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Tanoma (continued)

Summary of Recent News

The Tanoma coal mine is located in Pennsylvania and is owned by Tanoma Mining Co., Inc. Tanoma mines a 36 inch thick seam of the Lower Kittanning B Seam.

Sales & Supply

American Metals & Coal International (AMCI), the parent company of Tanoma Mining, was one of four suppliers selected by New Brunswick Power for its 450-MW Belledune power plant. AMCI supplies New Brunswick from its Tanoma mine. The New Brunswick contract is for up to 1.1 million tons per year (shared among the four suppliers) for one year beginning in May 1996 (CO 4/29/96). In addition, the suppliers had the option to supply coal during Winter 1996. The New Brunswick specifications are 10,660 Btu/lb., 4 lb./mmBtu SO₂, 12.4% ash, and 15% moisture. Since 1993, the Tanoma coal unit has provided approximately one third of the 1.2 million ton annual burn for New Brunswick (CO 2/12/96).

Updated: May 1997

Status: Operating

Urling No. 1

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Freeport (L)

County: Indiana

CORPORATE INFORMATION

Current Owner: Keystone Coal Mining

Parent Company: Rochester and Pittsburgh Coal Co.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: NA

Phone Number: 412-349-5800

Mailing Address: 655 Church Street

City: Indiana

State: PA

ZIP: 15701

GENERAL INFORMATION

Number of Employees at Mine: 217

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.70% - 1.58%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 12,800

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.5	0.8	0.7	0.9
Estimated Total Methane Liberated (million cf/day):	0.8	1.0	0.9	0.9
Emissions from Ventilation Systems:	0.8	1.0	0.9	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	646	484	452	380

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Urling No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.09
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.6%	3.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.6%	0.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Duquesne Light Co.

Parent Corporation of Utility: DQE

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	5.0	20.8
Mine Electricity Demand:	5.0	20.8
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.4	11.9
Assuming 60% Recovery Efficiency: ¹	2.0	17.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain: Open High Hills/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Peoples Natural Gas	
Distance to Pipeline (miles): 0.8	Pipeline Diameter (inches): 6.0
Owner of Next Nearest Pipeline: Texas Eastern Transmission	
Distance to Next Nearest Pipeline (miles): 16.7	Pipeline Diameter (inches): 20.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Urling No. 1 (continued)

Summary of Recent News

Operated by Keystone Coal Mining (Keystone), a subsidiary of Rochester and Pittsburgh Coal Company (R&P), the Urling No. 1 mine produced more than 600,000 tons of coal per year in 1994, 1995, and 1996. Most of the coal is supplied directly from the mine via conveyor belt to Pennsylvania Electric's Keystone Power plant in Pennsylvania.

In May 1993, the mine was part of the 1993 UMWA strike against the Bituminous Coal Operators Association (BCOA). As a result, production decreased significantly from previous years. During the strike, due to their dependence on coal produced from Urling No. 1, the Keystone and Connemaugh Power plants purchased spot and contract coal from other sources not affected by the strike. The Urling No. 1 mine alone accounted for almost one third of R&P's tonnage lost due to the strike (CW 7/19/93 and CW 5/31/93).

Keystone Coal Mining was recently involved in litigation regarding alleged tampering with dust samples from the Urling No. 1 Mine. In April 1994, however, a Federal Mine Safety and Health Review Commission Judge found that MSHA had failed to prove that Keystone Coal Mining intentionally tampered with the dust samples. Urling No. 1 was one of about 800 coal mines that had been cited for alleged tampering in 1991 (Coal 7/94).

In December 1995, Keystone closed the Jane, Emilie No. 4 and Margaret No. 11 underground mines due to high costs leaving the Emilie No. 1, Plumcreek, and Urling No. 1 mines operating. The President of Keystone warned that the remaining mines must lower costs and increase productivity in order to continue operating (CO 1/8/96 and CW 1/8/96). Keystone laid off 16 workers at the Urling No. 1 mine on December 30, 1996, in a continuing effort to drive down costs at Keystone. The layoffs resulted in cutting three production shifts to two production shifts and one maintenance shift. The company believes that improved maintenance will allow it to maintain similar production levels (CO 1/13/97).

Updated: May 1997

Status: Idle

Warwick

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Sewickley

County: Greene

CORPORATE INFORMATION

Current Owner: Duquesne Light/New Warwick Mining Co. (Aloe Mining)

Parent Company: DQE

Previous Owner(s): None

Previous or Alternate Name of Mine: Warwick Mine No. 3

MINE ADDRESS

Contact Name: Roger E. McHugh, Manager

Phone Number: 412-324-5651

Mailing Address: R.D. 1

City: Mount Morris

State: PA

ZIP: 15349

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.48% - 2.29%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 700

Seam Thickness (ft): 5.2

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.8	1.2	1.3	1.9
Estimated Total Methane Liberated (million cf/day):	0.9	1.0	1.3	1.1
Emissions from Ventilation Systems:	0.9	1.0	1.3	1.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	436	310	373	214

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Warwick (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.07	0.11
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.4%	2.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Duquesne Light Co.

Parent Corporation of Utility: DQE

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	14.1	56.4
Mine Electricity Demand:	10.9	45.1
Prep Plant Electricity Demand:	3.2	11.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ²	1.7	14.6
Assuming 60% Recovery Efficiency: ²	2.5	21.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.2
Assuming 60% Recovery Efficiency (Bcf): ²	0.2
Description of Surrounding Terrain: High Hills/Open High Hills	
Transmission Pipeline in County?: NA	
Owner of Nearest Pipeline: Columbia Gas of Pennsylvania, Inc.	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Warwick (continued)

Summary of Recent News

The Warwick mine is located in Greene County, Pennsylvania and is owned by Duquesne Light (Duquesne) and operated by New Warwick Mining (New Warwick). The Warwick mine exploits the Sewickley coal seam and has been plagued by high costs, water problems, and contract disputes.

In 1988, Duquesne Light closed its Warwick mine due to high mining costs. When Duquesne closed the mine, it negotiated a deal with the Pennsylvania Utility Commission to recover its investment in the mine (CO 9/18/95). However, the United Mine Workers picketed the utility and lobbied the PUC to cancel the utility's right to recover its investment (CO 9/18/95). In order to salvage the investment recovery, Duquesne solicited bids from contract operators. In 1990, Duquesne signed a deal with Aloe Mining, the parent company of New Warwick Mining and re-opened the mine.

Five years later, displeased over an unattended water issue, Duquesne aimed to terminate New Warwick as the mine contractor. At issue was the rising water in the inactive Shannopin mine which poses a danger to the integrity of Warwick. Shannopin is located in the Pittsburgh seam approximately 90 feet below Warwick. However, due to the nature of the terrain, a section of Shannopin which is collecting water is actually higher than some of Warwick's undeveloped reserves (CO 9/18/95). Migration of the water could infiltrate Warwick and possibly destroy the coal reserves. There is an estimated 900 million gallons of water in the closed Shannopin mine, which currently shows no indication of being re-opened (CO 9/18/95 ;CO 7/22/96).

The two companies possessed opposing view points on the severity and imminence of the flooding problem. Duquesne believed that unless the problem was solved quickly, the water would flood the mine and destroy the coal reserves (CO 9/18/95). On the other hand, Aloe/New Warwick claimed there was no danger, because the company has the pumping capacity to handle the possible water seepage. UMW District 4 sided with New Warwick on the matter (CO 9/18/95). In the end, the real issue was over who should pay for pumping and treating the water.

On September 5, 1995, Duquesne notified New Warwick that it was terminating the contract mining agreements and would seek a new operator on the grounds that New Warwick refused responsibility for the water problem (CO 9/25/95). New Warwick and the UMW fought back and filed for a court hearing to prevent the termination. Before the hearing made it to court, Duquesne and New Warwick worked out a compromise. Duquesne withdrew its termination after New Warwick agreed to construct an acid mine drainage facility at Warwick (CO 9/25/95).

Moreover, the two parties consented to arbitrate who should pay for treating the water expected to seep from the underlying Shannopin mine. Duquesne also agreed to withdraw a lien placed on a \$3 million letter of credit posted by New Warwick when it re-opened the mine in 1990 (CO 9/25/95).

In July 1996, the UMW local at Warwick approved a work-rule change allowing an alternative schedule and higher production. The prior work schedule at Warwick was three, eight-hour shifts per day, with Saturdays and Sundays optional. The new schedule involves two, ten-hour shifts per day, with the remaining four hour days available for maintenance and/or continued production (CO 7/22/96). The new schedule also includes seven-day-a-week production. These changes will lead to new hiring and will help advance production to approximately 1.8 million tons per year (CO 7/22/96). More than 1.5 million tons were produced for 1996.

In November 1996, Warwick was again plagued by geologic problems. A fracturing of the roof above the pan line brought Warwick's longwall to a halt 20 feet short of the end of a panel. The longwall is unrecoverable and Warwick abandoned it. For several weeks, workers at the mine were on a reduced schedule and on November 25th, New Warwick laid off 190 hourly UMW workers. A week later, Warwick recalled 69 workers to retrieve continuous miners (CO 12/9/96). Warwick will continue to operate using only continuous miner units. Duquesne and New Warwick reworked their contract with Duquesne purchasing less coal. In January 1997, New Warwick drove new entries into the reserve from the nearby idled Meadow Run mine (CO 12/23/96).

Warwick (continued)

Sales & Supply

New Warwick Mining mines the coal for Duquesne under a contract mining agreement and then sells most of the production to Duquesne under a separate sales agreement. The Duquesne/New Warwick sales contract involves about 1 million tons per year, delivered by barge mostly to Duquesne's Elrama plant. Both contracts expire in March 2000 (CO 9/18/95).

According to Duquesne's report to the Federal Energy Regulatory Commission, the costs varied from a low of \$24.95 per ton for 17,000 tons to a high of \$56.58 per ton for 33,000 tons (CO 9/18/95). The higher figure is believed to include the amount Duquesne is allowed to charge ratepayers for recovery of its investment in the mine. In May 1995, Elrama received 58,000 tons of New Warwick coal containing 12,435 to 12,560 Btu/lb., 1.7% to 1.9% sulfur and ~ 11% ash (CO 9/18/95).

In addition to the Duquesne sales in 1995, Duquesne allowed Aloe to sell the remaining production of ~ 400,000 tons per year of Warwick coal to other entities. Early in 1996, Duquesne again agreed to sales of another 200,00 tons per year to outside parties. Markets for the extra coal include Ohio Edison, Niagara Mohawk Power and US Natural Resources, which purchases coal for resale to others (CO 7/22/96).

6. Profiled Mines (continued)

Utah Mines

Aberdeen
Pinnacle
Soldier Canyon

Updated: May 1997

Status: Operating

Aberdeen

GEOGRAPHIC DATA

Basin: Western (Uinta)

State: UT

Coalbed: Aberdeen

County: Carbon

CORPORATE INFORMATION

Current Owner: Andalex Resources, Inc.

Parent Company: Andalex Resources, Inc.

Previous Owner(s): None

Previous or Alternate Name of Mine: Tower Division

MINE ADDRESS

Contact Name: Samuel Quigley, General Manager

Phone Number: 801-637-5385

Mailing Address: E. Airport Road

City: Price

State: UT

ZIP: 84501

GENERAL INFORMATION

Number of Employees at Mine: 84

Mining Method: Room & Pillar

Year of Initial Production: 1980

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: NA

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,991

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.3	0.3	0.5	2.4
Estimated Total Methane Liberated (million cf/day):	0.2	0.3	0.4	1.4
Emissions from Ventilation Systems:	0.2	0.3	0.4	1.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	225	360	276	210

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Aberdeen (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.09	0.14
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.5%	2.3%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.4%	0.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Price City Utilities, Utah Power & Light

Parent Corporation of Utility: PacifiCorp

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	18.2	72.9
Mine Electricity Demand:	14.1	58.3
Prep Plant Electricity Demand:	4.1	14.6
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	2.1	18.6
Assuming 60% Recovery Efficiency: ¹	3.2	27.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.3
Description of Surrounding Terrain: Tablelands; Open High/Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Mountain Fuel Supply	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Carbon

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Aberdeen (continued)

Summary of Recent News

The Aberdeen and Pinnacle mines in Carbon County, Utah, make up the Tower Division of Andalex Resources, Inc. The complex produces around 2.4 million tons of low-sulfur steam coal annually (CO 2/10/97 p.2).

In December 1996, the Aberdeen mine was forced to prematurely move its longwall to a new panel after overlying sandstone triggered a coal burst in the mine. Aberdeen lost some supply and as a result missed shipments to its domestic customers. The mine had, however, already completed shipments to its international customers at the time of the coal burst. Production resumed in the new panel in mid-January 1997, but the previous supply problems at Aberdeen created a tight coal market, in the west, during early 1997. As a result, one of Aberdeen's customers, Intermountain Power Agency (IPA), sought spot coal suppliers for its power plant in Delta, Utah. IPA is anticipating a higher burn rate in 1997 and thus wanted to test new coals (CO 2/10/97 p.2 and p.7).

Sales & Supply

The Aberdeen mine supplies Nevada Power and Intermountain Power Agency (IPA) domestically, and Taiwan Power and several Japanese utilities internationally.

In February 1996, Andalex Resources was chosen by Taiwan Power Co. to supply around 300,000 metric tons per year in a new long-term contract (CW 2/12/96 p.7).

In March 1996, Andalex and Coastal Coal Sales agreed to a token price reduction in shipments to Tohoku Electric Power Co.; the agreed price for Andalex's Pinnacle brand coal was \$38.39 per ton of coal. The prices "will form the basis for other settlements with Japanese utilities such as Chubu Electric Power Co., Chugoko Electric and EPDC" (CW 3/25/96 p.5).

In September 1996, Andalex began shipping coal to Sierra Pacific Power's Valmy power plant from the Aberdeen and Pinnacle mines, as part of a short-term sales agreement for around 100,000 tons of coal (CO 9/16/96 p.8). The Andalex coal has a higher Btu than that from any of Valmy's previous suppliers (CW 9/9/96 p.1). Sierra Pacific Power had planned to issue a formal request for proposal if further shipments were required after October 1996. The company, along with its partner in the Valmy plant, Idaho Power, recently paid \$5 million to cancel shipments of 315,000 tons of coal from the Black Butte mine, their former supplier (CO 9/16/96 p.8).

Updated: May 1997

Status: Closed

Pinnacle

GEOGRAPHIC DATA

Basin: Western (Uinta)

State: UT

Coalbed: Gilson & Centennial

County: Carbon

CORPORATE INFORMATION

Current Owner: Andalex Resources, Inc.

Parent Company: Andalex Resources, Inc.

Previous Owner(s): None

Previous or Alternate Name of Mine: Tower Division

MINE ADDRESS

Contact Name: Samuel Quigley, General Manager

Phone Number: 801-637-5385

Mailing Address: E. Airport Road

City: Price

State: UT

ZIP: 84501

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Room & Pillar

Year of Initial Production: 1980

Primary Coal Use: Steam

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: NA

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,991

Depth to Seam (ft): NA

Seam Thickness (ft): 7.0 - 9.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.8	1.3	1.4	0.0
Estimated Total Methane Liberated (million cf/day):	0.6	0.7	0.7	0.2
Emissions from Ventilation Systems:	0.6	0.7	0.7	0.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	290	195	181	0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pinnacle (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.05	0.07
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.3%	2.0%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Price City Utilities, Utah Power & Light

Parent Corporation of Utility: PacifiCorp

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	10.6	42.3
Mine Electricity Demand:	8.2	33.8
Prep Plant Electricity Demand:	2.4	8.5
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ²	1.1	9.3
Assuming 60% Recovery Efficiency: ²	1.6	13.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.1
Assuming 60% Recovery Efficiency (Bcf): ²	0.2
Description of Surrounding Terrain: Tablelands; Open High/Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Mountain Fuel Supply	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Carbon

Distance to Plant (miles): NA

Boiler Capacity (MW): 188.0

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Pinnacle (continued)

Summary of Recent News

Andalex Resources owns and operates the Pinnacle mine, which is located in Utah. The mine is part of the Tower Division mining complex at Andalex Resources, which also includes the neighboring Aberdeen mine. In October 1994, Andalex installed a longwall mining system at Pinnacle. After experiencing some early break-in problems, the mine began producing coal of slightly higher quality than previously produced with continuous miners (CW 10/24/94). Despite the installation of a longwall and the production of higher quality coal, the Pinnacle mine was closed in November 1995 for economic reasons. Pinnacle had been very active in the export market to Japan before its closure.

Sales & Supply

In 1994, Andalex Resources supplied 60,000 metric tons of Pinnacle spot coal to Japan's Chugoku Electric Power Co. (CW 9/5/94). As mentioned earlier, Japanese utilities were a major purchaser of Pinnacle coal before the mine's closure.

Updated: May 1997

Status: Operating

Soldier Canyon

GEOGRAPHIC DATA

Basin: Western (Uinta)

State: UT

Coalbed: Rock Canyon & Sunnyside

County: Carbon

CORPORATE INFORMATION

Current Owner: Soldier Creek Coal Co.

Parent Company: Atlantic Richfield/ITOCHU Corp.

Previous Owner(s): Coastal States Energy Co.

Previous or Alternate Name of Mine: Soldier Creek

MINE ADDRESS

Contact Name: J.S. Noyes, General Mine Foreman

Phone Number: 801-637-6360

Mailing Address: Nine Mile Canyon Rd., P.O. Box 1

City: Price

State: UT

ZIP: 84501

GENERAL INFORMATION

Number of Employees at Mine: 87

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.40% - 0.50%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 11,991

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.5	0.6	0.5	1.0
Estimated Total Methane Liberated (million cf/day):	6.6	5.2	3.3	3.4
Emissions from Ventilation Systems:	3.3	2.6	3.3	3.4
Estimated Methane Drained:	3.3	3.3	0.0	0.0
Estimated Specific Emissions (cf/ton):	5,274	3,252	2,505	1,271

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Soldier Canyon (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.22	0.33
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	9.3%	14.0%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	2.1%	3.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Price City Utilities, Utah Power & Light

Parent Corporation of Utility: PacifiCorp

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	5.7	23.4
Mine Electricity Demand:	5.7	23.4
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	5.2	45.1
Assuming 60% Recovery Efficiency: ¹	7.7	67.7

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.5
Assuming 60% Recovery Efficiency (Bcf): ¹	0.7
Description of Surrounding Terrain: Tablelands; Open High/Low Mountains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Mountain Fuel Supply	
Distance to Pipeline (miles): 2.5	Pipeline Diameter (inches): 20.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Soldier Canyon (continued)

Summary of Recent News

The Soldier Canyon mine is located in Carbon County, Utah. In the year-long period ending October 31, 1995, Soldier Canyon produced 537,560 tons of coal, generating 113.98 tons per manday. Soldier Canyon is a room-and-pillar mine, but there has been some discussion of installing a longwall in the future if markets continue to develop (CO 3/4/96 p.1).

Soldier Canyon is one of several highly profitable holdings owned by Coastal Coal, a subsidiary of Coastal Corp., primarily a gas pipeline company (Coal 4/96 p.6). In 1995, Coastal Coal reported revenues of \$459.6 million and operating profits of \$98.7 million (Coal 4/96 p.5).

Early in 1996, Coastal Corp. put Coastal Coal up for sale, and analysts valued the company at around \$800 million (CO 3/4/96). Coastal Coal owns three mines in Utah (Soldier Canyon, Sufco and Skyline), as well as mines in Kentucky, Virginia, and West Virginia, which are part of Coastal Corp.'s ANR Coal subsidiary (CO 3/4/96). The Utah mines in particular were expected to generate a lot of interest, from potential buyers hoping to expand westward, due to their high profitability in the low-sulfur western market (Coal 4/96 p.5).

In October 1996, Coastal Corp. announced that its western coal operations had been purchased by a limited partnership of Atlantic Richfield Co. and ITOCHU Corp. of Japan. The purchase included Coastal Corp. subsidiaries, Coastal States Energy Co., Southern Utah Fuel Co., Soldier Creek Coal Co., Skyline Coal Co., and a 9% interest in LAXT. Coastal Corp. retained ANR Coal Co. and its mines and reserves in Kentucky, Virginia, and West Virginia, but eventually these holdings may be sold as Coastal attempts to reduce its debt (CO 12/23/96 p.3; CW 10/28/96 p.1). ARCO, with a 65% interest in the new partnership, will manage the operations. ITOCHU, with a 35% interest, has served as a trading channel for Coastal's western coal since the 1980s and will provide marketing expertise. The companies have not yet named their joint venture (CW 10/28/96 p.1).

Currently, Soldier Canyon is Coastal's only underground mine without a longwall, but there is speculation that the ARCO-ITOCHU partnership may install one and push production up to around 3.5 million tons per year (CO 12/23/96 p.3).

6. Profiled Mines (continued)

Virginia Mines

Buchanan No. 1

Bullitt

McClure No. 1

McClure No. 2

VP No. 3

VP No. 8

Updated: May 1997

Status: Open/Using

Buchanan No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Pocahontas No. 3

County: Buchanan

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: Buchanan

MINE ADDRESS

Contact Name: Douglas LaForce, Mine Foreman

Phone Number: 703-498-4564

Mailing Address: P.O. Box 230, Route 632

City: Mavisdale

State: VA

ZIP: 24627

GENERAL INFORMATION

Number of Employees at Mine: 401

Mining Method: Longwall

Year of Initial Production: 1983

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.72% - 0.82%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,900

Depth to Seam (ft): 1,700

Seam Thickness (ft): 5.5 - 6.3

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	2.8	3.0	3.2	3.6
Estimated Total Methane Liberated (million cf/day):	33.8	33.0	30.2	NA
Emissions from Ventilation Systems:	13.5	13.2	12.1	12.8
Estimated Methane Drained:	20.3	19.8	18.1	NA
Estimated Specific Emissions (cf/ton):	4,327	4,004	3,472	NA

Estimated Current Drainage Efficiency: NA

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Buchanan No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	1.96	2.94
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	21.8%	32.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	5.0%	7.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	23.9	95.4
Mine Electricity Demand:	18.4	76.3
Prep Plant Electricity Demand:	5.4	19.1
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ¹	45.8	401.5
Assuming 60% Recovery Efficiency: ¹	68.8	602.3

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	4.4
Assuming 60% Recovery Efficiency (Bcf): ¹	6.6
Description of Surrounding Terrain:	Open Low Mountains/Low Mountains
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Mine owns pipeline that connects to dist. line
Distance to Pipeline (miles):	0.0
Pipeline Diameter (inches):	NA
Owner of Next Nearest Pipeline:	Consolidated Natural Gas Supply Co. (CNG)
Distance to Next Nearest Pipeline (miles):	1.0
Pipeline Diameter (inches):	8.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; drainage efficiency is unknown.

Buchanan No. 1 (continued)

Summary of Recent News

In late 1995, MCN Corporation, a Michigan-based gas supplier, announced that it had signed a deal to buy extensive methane reserves, including 130 methane-producing wells and some attendant gas pipelines, from CONSOL. CONSOL has stated that the methane reserves being sold are those associated with the VP No. 3, VP No. 8, and part of the Buchanan No. 1 mine (CO 12/4/95).

Buchanan No. 1, along with the two Island Creek mines, already recovers methane for pipeline sales. A more detailed discussion of Buchanan No. 1 is included in the "Overview of Current Methane Recovery Projects."

Updated: May 1997

Status: Idle

Bullitt

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Dorchester

County: Wise

CORPORATE INFORMATION

Current Owner: Westmoreland Coal Co.

Parent Company: Westmoreland Resources, Inc.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Joe Wagner, Gen. Mine Foreman

Phone Number: 540-523-9390

Mailing Address: P.O. Box A&B

City: Big Stone Gap

State: VA

ZIP: 24219

GENERAL INFORMATION

Number of Employees at Mine: 195 ¹

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 4

Sulfur Content of Coal Produced: 1.30%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,600

Depth to Seam (ft): 400

Seam Thickness (ft): 4.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.6	0.7	0.3	0.0
Estimated Total Methane Liberated (million cf/day):	0.8	0.6	0.5	0.5
Emissions from Ventilation Systems:	0.8	0.6	0.5	0.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	530	334	536	0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

¹ Number of employees based on when mine was in operation.

Bullitt (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.03	0.05
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.7%	5.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.9%	1.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	2.6	10.2
Mine Electricity Demand:	2.0	8.2
Prep Plant Electricity Demand:	0.6	2.0
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ²	0.8	6.6
Assuming 60% Recovery Efficiency: ²	1.1	10.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.1
Assuming 60% Recovery Efficiency (Bcf): ²	0.1
Description of Surrounding Terrain: Open Hills/Low Mountains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Pittston	
Distance to Pipeline (miles): 5.8	Pipeline Diameter (inches): 12.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

Bullitt (continued)

Summary of Recent News

Bullitt is a longwall mine located in Wise County, Virginia. The mine produces steam coal with an average sulfur content of around 1.30% (1997 Keystone Coal Industry Manual). The mine is owned by Westmoreland Coal, a company based in Philadelphia, Pennsylvania that leases a large portion of its reserves from Penn Virginia Corp. (CO 8/7/95 p.8). The mine employs 195 workers and the miners are affiliated with the UMW. In early August 1995, Westmoreland idled the Bullitt mine, as well as four of its other deep mines in Virginia, and the company's High Sprint surface mine (CO 8/7/95 p.8).

Westmoreland has recently begun selling off its properties in an effort to reduce its debt; many of the company's Virginia mining operations have already been sold or are currently on the market. Much of Westmoreland's financial difficulty stems from the company's past labor-related obligations, amounting to tens of millions of dollars (CO 8/7/95 p.8).

In May 1996, Roaring Fork Mining purchased Westmoreland's Pine Branch operation, and Westmoreland's Wentz operation was sold to Stonega Mining & Processing, both in non-cash sales (CO 5/27/96 p.5). The buyers agreed to assume Westmoreland's union obligations, reclamation and environmental liabilities, equipment leases, and post-retirement medical benefit obligations for any former Westmoreland workers that they hired (CO 5/27/96 p.5). In June 1996, Roaring Fork entered into discussions with Westmoreland about purchasing the Bullitt mine and its prep plant and transloader, but the parties appear to have been unable to reach an agreement (CO 7/29/96 p.4).

In September 1996, Westmoreland sold its Pierrepont and Holton mines in Virginia to David Maynard of Intrepid Coal (CO 9/30/96 p.2). The company was still hoping to find buyers for the Bullitt mine, its prep plant/transloader, reserves at Inman and Stone Mountain, some surface equipment and two contract mining operations (CO 9/30/96 p.3).

By December 1996, Westmoreland's obligations to the UMW retiree health funds had become so onerous that the company was contemplating Chapter 11 bankruptcy (CO 12/23/96 p.3).

Updated: May 1997

Status: Closed

McClure No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Jawbone

County: Dickenson

CORPORATE INFORMATION

Current Owner: Clinchfield Coal

Parent Company: Pittston Coal Management Co.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Gene Brinager, Manager

Phone Number: 540-495-4244

Mailing Address: P.O. Box 5100

City: Lebanon

State: VA

ZIP: 24266

GENERAL INFORMATION

Number of Employees at Mine: 54 ¹

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 0.70% - 1.82%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 11,507

Depth to Seam (ft): 760

Seam Thickness (ft): 4.1 - 5.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.1	1.0	0.1	0.0
Estimated Total Methane Liberated (million cf/day):	3.7	3.7	2.4	1.4
Emissions from Ventilation Systems:	3.7	3.7	2.4	1.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	1,210	1,407	11,811	0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

¹ Number of employees based on when mine was in operation.

McClure No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ²	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.16	0.23
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	89.4%	134.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	20.5%	30.8%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	0.6	2.2
Mine Electricity Demand:	0.4	1.8
Prep Plant Electricity Demand:	0.1	0.4
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ²	3.6	31.9
Assuming 60% Recovery Efficiency: ²	5.5	47.8

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ²	0.4
Assuming 60% Recovery Efficiency (Bcf): ²	0.5
Description of Surrounding Terrain:	Open Low Mountains/Low Mountains
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Pittston
Distance to Pipeline (miles):	5.8
Pipeline Diameter (inches):	12.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Furniture and clothing manufacturing.

² Drainage efficiency is projected; this mine currently does not have a drainage system.

McClure No. 1 (continued)

Summary of Recent News

Although McClure No. 1 and McClure No. 2 belong to the same mine complex, separate profiles are provided for each mine.

McClure No. 1, owned by Clinchfield Coal and managed by Pittston Coal, is a metallurgical coal mine located in western Virginia. In March 1995, McClure No. 1 was closed due to declining prices in the metallurgical coal market (CO 10/31/94). The mine had been a major source of metallurgical-grade coal for a number of years.

In 1983, the McClure No. 1 mine was the site of one of the worst mining accidents in U.S. history. On June 21, 1983, a methane explosion killed seven miners and injured three. The MSHA investigated the explosion and issued citations to McClure's owner, Clinchfield Coal, for safety violations.

According to Pittston, the mine is permanently closed because it has run out of economically mineable coal (CO 3/6/95). Pittston has shifted its emphasis from the export metallurgical coal market to domestic steam coal sales (CO 09/05/94). Prior to its closing, McClure No. 1 had been Pittston's only longwall mine. The closure affected 177 employees and was believed to have been partially responsible (along with three other mine closings) for the declining value of Pittston Minerals Group's (PMG) stock in April 1995 (CW 3/17/95; CO 10/31/94).

Analysts have predicted that PMG's stock could drop further due to more underground metallurgical coal mine closings in 1995. Industry watchers speculate that these additional mine closings could make Pittston Coal a candidate for sale, with Cyprus Amax Coal as a likely buyer (CW 3/17/95).

In 1995, the coal market experienced a rise in sales of metallurgical coals, especially those slated for export. Sources around the world expected prices for hard coking coals to rise \$4/metric ton or more for fiscal 1995 (CW 1/2/95). However, the expected price increases were still not enough to keep Pittston's McClure No. 1 mine open.

Updated: May 1997

Status: Operating

McClure No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Jawbone

County: Dickenson

CORPORATE INFORMATION

Current Owner: Clinchfield Coal

Parent Company: Pittston Coal Management Co.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Gene Brinager, Manager

Phone Number: 540-495-4244

Mailing Address: P.O. Box 5100

City: Lebanon

State: VA

ZIP: 24266

GENERAL INFORMATION

Number of Employees at Mine: 76

Mining Method: Room & Pillar

Year of Initial Production: NA

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 6

Sulfur Content of Coal Produced: 1.00%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,900

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.4	0.3	0.3	0.4
Estimated Total Methane Liberated (million cf/day):	0.5	0.6	0.6	1.0
Emissions from Ventilation Systems:	0.5	0.6	0.6	1.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	514	738	629	1,006

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

McClure No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.06	0.10
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	6.3%	9.5%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.4%	2.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	2.7	10.9
Mine Electricity Demand:	2.1	8.7
Prep Plant Electricity Demand:	0.6	2.2
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.5	13.3
Assuming 60% Recovery Efficiency: ¹	2.3	19.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.2
Description of Surrounding Terrain:	Open Low Mountains/Low Mountains
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Pittston
Distance to Pipeline (miles):	5.8
Pipeline Diameter (inches):	12.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Furniture and clothing manufacturing.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

McClure No. 2 (continued)

Summary of Recent News

Although McClure No. 1 and McClure No. 2 belong to the same mine complex, separate profiles are provided for each mine.

McClure No. 2 is owned and operated by Clinchfield Coal Co. and is located in Virginia. The mine produces coal from the Jawbone seam. The only additional information available for McClure No. 2 is from the Keystone Coal Industry Manual (1997) and is included on the previous two pages.

Updated: May 1997

Status: Open/Using

VP No. 3

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Pocahontas No. 3

County: Buchanan

CORPORATE INFORMATION

Current Owner: Consolidation Coal, Island Creek Coal

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): Island Creek Coal

Previous or Alternate Name of Mine: Virginia Pocahontas No. 3

MINE ADDRESS

Contact Name: Paul Kvederis, Manager Public Relations

Phone Number: 703-935-4635

Mailing Address: Drawer L

City: Oakwood

State: VA

ZIP: 24631

GENERAL INFORMATION

Number of Employees at Mine: 211

Mining Method: Longwall

Year of Initial Production: 1970

Primary Coal Use: Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.80%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,000

Depth to Seam (ft): 1,875

Seam Thickness (ft): 5.4

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.9	1.7	1.8	1.6
Estimated Total Methane Liberated (million cf/day):	14.9	14.1	13.9	NA
Emissions from Ventilation Systems:	7.6	7.2	7.1	6.9
Estimated Methane Drained:	7.3	6.9	6.8	NA
Estimated Specific Emissions (cf/ton):	5,732	2,963	2,772	NA

Estimated Current Drainage Efficiency: NA

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

VP No. 3 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.90	1.36
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	18.6%	27.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	4.3%	6.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	13.8	55.0
Mine Electricity Demand:	10.6	44.0
Prep Plant Electricity Demand:	3.1	11.0
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ¹	21.1	184.8
Assuming 60% Recovery Efficiency: ¹	31.6	277.2

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	2.0
Assuming 60% Recovery Efficiency (Bcf): ¹	3.0
Description of Surrounding Terrain: Open Low Mountains/Low Mountains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Mine owns pipeline that connects to dist. line	
Distance to Pipeline (miles): 0.0	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)	
Distance to Next Nearest Pipeline (miles): 3.3	Pipeline Diameter (inches): 6.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; drainage efficiency is unknown.

VP No. 3 (continued)

Summary of Recent News

The VP No. 3 mine is owned by Island Creek Coal, a subsidiary of the CONSOL Coal Group. The mine is located in Buchanan County, Virginia and is one of two operating VP mines. The other operating mine is VP No. 8. The mine, which is equipped with a longwall, produces coal out of the Pocahontas No. 3 seam, mostly for the export metallurgical market. In 1996, about 245 workers were laid off due to an idling of the mine. It was the first cutback VP No. 3 had seen in years and was an indication of a softening export metallurgical market (CO 6/17/96).

On June 7, 1996, Island Creek Coal idled the VP No. 3 mine, citing an over-supply of low-volatile metallurgical coal (the mine's product) as the reason. On June 7, 1996, CONSOL said that they expected the mine would be idled for less than six months. By October 1, 1996, 245 laid-off workers were being recalled to work, although at the time of the recall they were only being guaranteed employment of two months since the recall was not due to any market changes, but rather was based on an internal company decision. When CONSOL idled the mine the longwall was in the middle of a panel. CONSOL decided it was better to mine out the current panel and remove the longwall equipment so as to avoid any potential damage to the longwall during an extensive shutdown (CO 9/30/96). Despite guaranteed employment of only two months and CONSOL's intentions to idle the VP No. 3 mine during the 14-day period beginning December 4, 1996, the idling did not occur. As of late-February 1997, the mine was still operational and has not been idled (CO 2/24/97). In the end, the mine's long-term future depends on CONSOL's success in acquiring contracts for its export metallurgical coal (CO 12/23/96).

In late 1995, MCN Corporation, a Michigan-based gas supplier, announced that it had signed a deal to buy extensive methane reserves, 130 producing methane wells and some attendant gas pipelines from CONSOL. CONSOL has stated that the methane reserves being sold are those associated with the VP No. 3, VP No. 8, and part of the Buchanan No. 1 mine (CO 12/4/95).

Island Creek's VP mines recover methane for pipeline sales. A more detailed discussion of these mines is included in the section on existing methane recovery projects.

Updated: August 1997

Status: Open/Using

VP No. 8

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Pocahontas No. 3

County: Buchanan

CORPORATE INFORMATION

Current Owner: Consolidation Coal, Island Creek Coal

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): Island Creek Coal

Previous or Alternate Name of Mine: Combined VP No. 5 & VP No. 6

MINE ADDRESS

Contact Name: Paul Kvederis, Manager Public Relations

Phone Number: 703-597-7426

Mailing Address: Drawer L

City: Deskins

State: VA

ZIP: 24631

GENERAL INFORMATION

Number of Employees at Mine: 333

Mining Method: Longwall

Year of Initial Production: 1994

Primary Coal Use: Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.80% - 0.90%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,000

Depth to Seam (ft): 2,050

Seam Thickness (ft): 5.0 - 5.1

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	2.2	2.3	2.8
Estimated Total Methane Liberated (million cf/day):	26.6	20.2	25.0	NA
Emissions from Ventilation Systems:	13.3	10.1	12.5	13.2
Estimated Methane Drained:	13.3	10.1	12.5	NA
Estimated Specific Emissions (cf/ton):	5,884	3,339	3,974	NA

Estimated Current Drainage Efficiency: NA

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

VP No. 8 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	1.62	2.43
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	26.6%	39.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	6.1%	9.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	17.2	68.9
Mine Electricity Demand:	13.3	55.1
Prep Plant Electricity Demand:	3.9	13.8
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency: ¹	37.9	331.8
Assuming 60% Recovery Efficiency: ¹	56.8	497.7

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	3.6
Assuming 60% Recovery Efficiency (Bcf): ¹	5.5
Description of Surrounding Terrain:	Open Low Mountains/Low Mountains
Transmission Pipeline in County?:	No
Owner of Nearest Pipeline:	Mine owns pipeline that connects to dist. line
Distance to Pipeline (miles):	0.0
Pipeline Diameter (inches):	NA
Owner of Next Nearest Pipeline:	Consolidated Natural Gas Supply Co. (CNG)
Distance to Next Nearest Pipeline (miles):	1.0
Pipeline Diameter (inches):	6.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage system already in use; drainage efficiency is unknown.

VP No. 8 (continued)

Summary of Recent News

The VP No. 8 mine was born out of the consolidation of the VP No. 5 and VP No. 6 mines. The consolidation occurred in mid-1994 (CO 5/9/94). The VP No. 8 mine is owned by Island Creek Coal, a subsidiary of the CONSOL Coal Group. The mine is located in Buchanan County, Virginia and is one of two operating VP mines. The other mine is VP No. 3. The mine, which is equipped with a longwall, produces coal out of the Pocahontas No. 3 seam, mostly for the export metallurgical market. The mine recovers methane for pipeline sales.

In April 1996, Island Creek Coal laid off 90 workers at the VP No. 8 mine, citing a need to improve the cost structure as the reason. The mine was not idled though. About 450 people had worked at the mine before the layoffs (CO 4/29/96). By February 1997, with the mine's cost structure not improving and an over supply of low-volatile metallurgical coal (the mine's product) on the market, Island Creek coal laid off an additional 250 UMW-represented employees. On February 17, 1997, Island Creek Coal idled the VP No. 8 mine (CO 2/24/97). However, in August, 1997, CONSOL restarted the mine (CO 8/18/97). CONSOL officials could not say whether there was anything in particular that caused the mine to reopen.

In late 1995, MCN Corporation, a Michigan-based gas supplier, announced that it had signed a deal to buy extensive methane reserves, 130 producing methane wells and some attendant gas pipelines from CONSOL. CONSOL has stated that the methane reserves being sold are those associated with the VP No. 3, VP No. 8, and part of the Buchanan No. 1 mine (CO 12/4/95).

Island Creek's VP mines recover methane for pipeline sales. A more detailed discussion of these mines is included in the section on current methane recovery projects.

6. Profiled Mines (continued)

West Virginia Mines

Arkwright No. 1
Baylor No. 1
Blacksville No. 2
Eagle Nest
Federal No. 2
Humphrey No. 7
Loveridge No. 22
Maple Meadow No. 1
McElroy
Pinnacle No. 50
Robinson Run No. 95
Sentinel
Shoemaker
Windsor

Updated: May 1997

Status: Closed

Arkwright No. 1

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Monongalia

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: Arkwright

MINE ADDRESS

Contact Name: Terry Suder, Mine Superintendent

Phone Number: 304-798-3118

Mailing Address: P.O. Box 100

City: Osage

State: WV

ZIP: 26543

GENERAL INFORMATION

Number of Employees at Mine: 263 ¹

Mining Method: Longwall

Year of Initial Production: 1924

Primary Coal Use: Steam

Mine Life Expectancy (years): 0

Sulfur Content of Coal Produced: 2.15% - 2.63%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,500

Depth to Seam (ft): 820

Seam Thickness (ft): 6.7 - 7.1

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.6	2.0	1.4	0.0
Estimated Total Methane Liberated (million cf/day):	3.5	2.2	2.7	0.0
Emissions from Ventilation Systems:	2.1	1.3	1.6	0.0
Estimated Methane Drained:	1.4	0.9	1.1	0.0
Estimated Specific Emissions (cf/ton):	800	404	687	0

Estimated Current Drainage Efficiency: Mine closed

Drainage System Used: Vertical Gob, Horizontal Pre-Mine (Mine closed; drainage system not active)

¹ Number of employees based on when mine was in operation.

Arkwright No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency	
(Based on 1995 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.17	0.26
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	4.8%	7.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.1%	1.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1995 data):	10.6	42.5
Mine Electricity Demand:	8.2	34.0
Prep Plant Electricity Demand:	2.4	8.5
Potential Generating Capacity (1995 data)		
Assuming 40% Recovery Efficiency:	4.0	35.4
Assuming 60% Recovery Efficiency:	6.1	53.1

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1995 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf):	0.4
Assuming 60% Recovery Efficiency (Bcf):	0.6
Description of Surrounding Terrain:	Open Low Mountains/High Hills
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Consolidated Natural Gas Supply Co. (CNG)
Distance to Pipeline (miles):	0.2
Pipeline Diameter (inches):	8.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Pharmaceuticals, chemicals, apparel, and glass manufacturing; hospitals, university, and other municipal buildings.

Arkwright No. 1 (continued)

Summary of Recent News

The Arkwright mine is owned by CONSOL. The mine is located in Monongalia County, West Virginia and produces high-sulfur coal. With a reduced market for high-sulfur coal as a result of new clean air laws, Arkwright was closed in late 1995.

In late 1994, the UMWA District 31 office launched a public effort to save CONSOL's Osage No. 3, Arkwright, and Humphrey mines from being closed. All three mines employed UMW members and produced high-sulfur coal, which was seeing a rapid market decline as a result of new clean-air laws. CONSOL had previously indicated that Arkwright might close by September 1995 (CO 9/5/94).

To save the Arkwright, Osage No. 3 and Humphrey mines from closure, the UMW embarked on a number of tactics including:

- asking the West Virginia governor to authorize the purchase of SO₂ emission credits, which would be used to compensate utilities that burn coal from those mines. The union's argument was that keeping the mines operational would be cheaper for the state in the long run than providing welfare and other social benefits to miners and their families who would be affected if the mines were closed (CO 10/17/94).
- discussing an employee buyout of the Osage, Humphrey and Arkwright mines from CONSOL. No firm commitments were made by either CONSOL or the UMWA (CO 2/13/95).
- planning to contact several coal companies to see whether they were interested in buying the Osage and Arkwright mines. The coal companies to be contacted were not disclosed (CO 2/20/95).

On July 19, 1995, despite the union's efforts to save the mine, CONSOL issued a 60 day WARN layoff notice to 214 workers at Arkwright, saying that production would cease there and permanent closure of the mine would begin during the 14-day period starting September 25, 1995 (CO 7/24/95). On October 7, 1995, CONSOL closed its Arkwright mine (CW 10/16/95). When the mine closed, there were some reserves remaining. CONSOL, however, decided that those reserves could not be economically mined at the time (CO 10/16/95).

Updated: May 1997

Status: Operating

Baylor No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Beckley

County: Raleigh

CORPORATE INFORMATION

Current Owner: Baylor Mining, Inc.

Parent Company: Baylor Mining, Inc.

Previous Owner(s): None

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Robert Worley, President

Phone Number: 394-253-7990

Mailing Address: P.O. Box 1435

City: Beckley

State: WV

ZIP: 25901

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Room & Pillar

Year of Initial Production: 1993

Primary Coal Use: Steam

Mine Life Expectancy (years): 9

Sulfur Content of Coal Produced: 0.72%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 14,750

Depth to Seam (ft): 383

Seam Thickness (ft): 2.0 - 4.2

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.003	0.3	0.6	0.9
Estimated Total Methane Liberated (million cf/day):	NA	0.3	0.9	1.2
Emissions from Ventilation Systems:	NA	0.3	0.9	1.2
Estimated Methane Drained:	NA	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	NA	389	513	462

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Baylor No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.08	0.12
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.7%	4.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.6%	0.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	5.5	22.8
Mine Electricity Demand:	5.5	22.8
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	1.8	15.9
Assuming 60% Recovery Efficiency: ¹	2.7	23.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.2
Assuming 60% Recovery Efficiency (Bcf): ¹	0.3
Description of Surrounding Terrain: Low Mountains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Baylor No. 1 (continued)

Summary of Recent News

The Baylor No. 1 mine is located near the town of Eccles in Raleigh County, West Virginia. It produces around 800,000 tons of low-volatile premium quality metallurgical coal per year from the Beckley coal seam. Baylor No. 1 opened in 1993, and began full production in September of 1994 under Baylor Mining, Inc. The mine is served by CTX Transportation.

In 1994 the Anker Group, a non-union company, bought a controlling interest in the Baylor No. 1 mine from the original developers. Anker Group now owns 95% of Beckley Smokeless L.L.C., the company now responsible for management of the mine. Anker also controls reserves surrounding the Baylor No. 1 mine in the Beckley and Pocahontas No. 3 coal seams (CO 4/3/95 p.6). Soon after the Baylor No. 1 mine opened it became the target of an organization effort by the UMW's Dist. 29 in southern West Virginia (CO 11/7/94 p.3).

Sales & Supply

The Baylor No. 1 mine sells all of its coal in one-year contracts to various steel industry customers.

Updated: May 1997

Status: Open/Using

Blacksville No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Monongalia

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: W.G. DeVine, Mine Superintendent

Phone Number: 304-662-6121

Mailing Address: P.O. Box 24

City: Wana

State: WV

ZIP: 26590

GENERAL INFORMATION

Number of Employees at Mine: 479

Mining Method: Longwall

Year of Initial Production: 1971

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 1.86% - 2.43%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 1,375

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.9	3.7	3.8	3.4
Estimated Total Methane Liberated (million cf/day):	9.3	8.0	10.0	10.0
Emissions from Ventilation Systems:	5.6	4.8	6.0	6.0
Estimated Methane Drained:	3.7	3.2	4.0	4.0
Estimated Specific Emissions (cf/ton):	1,801	782	958	1,074

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Blacksville No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.65	0.97
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	7.1%	10.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.6%	2.4%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	25.5	101.9
Mine Electricity Demand:	19.7	81.6
Prep Plant Electricity Demand:	5.8	20.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	15.2	132.7
Assuming 60% Recovery Efficiency: ¹	22.7	199.1

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.5
Assuming 60% Recovery Efficiency (Bcf): ¹	2.2
Description of Surrounding Terrain:	Open Low Mountains/High Hills
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Consolidated Natural Gas Supply Co. (CNG)
Distance to Pipeline (miles):	0.4
Pipeline Diameter (inches):	10.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Rivesville

Distance to Plant (miles): 17.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Pharmaceuticals, chemicals, apparel, and glass manufacturing; hospitals, university, and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Blacksville No. 2 (continued)

Summary of Recent News

The Blacksville No. 2 mine is owned by CONSOL. The mine is located in Monongalia County, West Virginia and produces high-sulfur coal. The mine is longwall equipped.

The Blacksville No. 2 mine has had a longwall since 1992. The longwall was installed to improve productivity (CW 8/26/96). Although productivity did increase earlier this decade, Blacksville No. 2 has dropped from the fifth-highest, domestic, underground, coal producing mine in 1992 to the seventeenth-highest, domestic, underground, coal producing mine in 1995. In 1992, the mine produced 4.2 million tons while in 1995, the mine produced 3.8 million tons (Keystone 1994; Keystone 1997). Despite a drop in production, in late 1994, CONSOL indicated that the Blacksville No. 2 mine would operate for another 15 years. Surprising was the company's commitment to this mine despite the company's closure of the Humphrey and Arkwright mines, which are neighboring mines and, which produce a similar quality coal (CO 10/17/94).

Methane is currently being recovered from the Blacksville No. 2 mine. Additional information on the Blacksville No. 2 methane recovery project is included in the section on existing methane recovery projects.

Sales & Supply

Purchasers of Blacksville No. 2 coal include New York State Electric & Gas (NYSE&G), Metropolitan Edison, and Ontario Hydro (CW 11/11/96; CW 1/8/96; CW 8/7/95; CW 10/3/94). In November 1996, NYSE&G bought 301,000 tons of contract and spot coal from the Blacksville No. 2 mine.

The mine will partly provide 150,000 tons/yr of coal required by Baltimore Gas & Electric. The contract is a two year contract, expiring December 31, 1997. (CO 1/8/96.)

Updated: May 1997

Status: Operating

Eagle Nest

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Millard

County: Boone

CORPORATE INFORMATION

Current Owner: A. T. Massey Coal Co., Inc.

Parent Company: Bethlehem Steel Corp.

Previous Owner(s): BethEnergy Mines Inc., Eagle Nest Inc.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Richard Stickler, Senior Manager

Phone Number: 304-245-8236

Mailing Address: P.O. Box 270

City: Van

State: WV

ZIP: 25206

GENERAL INFORMATION

Number of Employees at Mine: 425

Mining Method: Longwall

Year of Initial Production: 1990

Primary Coal Use: Metallurgical

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 0.85% - 0.91%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 14,344

Depth to Seam (ft): 800

Seam Thickness (ft): 5.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	0.9	1.3	1.7	1.4
Estimated Total Methane Liberated (million cf/day):	0.5	0.5	0.6	0.6
Emissions from Ventilation Systems:	0.5	0.5	0.6	0.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	202	137	131	159

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Eagle Nest (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.04	0.06
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.0%	1.4%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.2%	0.3%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	10.4	41.4
Mine Electricity Demand:	8.0	33.1
Prep Plant Electricity Demand:	2.4	8.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.9	8.0
Assuming 60% Recovery Efficiency: ¹	1.4	11.9

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.1
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain:	Low Mountains/Open Low Mountains
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Mountaineer Gas Co.
Distance to Pipeline (miles):	NA
Pipeline Diameter (inches):	NA
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Eagle Nest (continued)

Summary of Recent News

Eagle Nest is a longwall/continuous mine operation located in Boone County, West Virginia. It produces around 1.5 million tons of low-volatile metallurgical coal per year, with a sulfur content of around 0.88% (1997 Keystone Coal Industry Annual). Half of Eagle Nest's coal goes to Bethlehem Steel, the parent company of the mine's former owner, BethEnergy, while the other half is sold on the open metallurgical market (CO 9/21/95 p.2). Eagle Nest's miners are represented by the UMW.

A. T. Massey Coal had expressed interest in purchasing the Eagle Nest mine from BethEnergy since the early 1990s, but relations between Massey and the UMW, which represents Eagle Nest's workers, have been strained. In 1992, representatives from Massey toured the Eagle Nest complex, triggering a two-day protest strike by UMW workers at the mine. In late 1995, BethEnergy struck an agreement with A. T. Massey, under which the latter would market all Eagle Nest coal, including the coal shipped to Bethlehem Steel (CO 1/8/96 p.4). In the past few years, Massey has slowly been increasing its market share, both through the agreement to market Eagle Nest's coal, and supply agreements with U.S. Steel, Steel Company of Canada (Stelco) and Algoma Steel (CO 1/15/96 p.8). In August 1996, it appeared that Massey might also be interested in purchasing Peabody Holding's Eastern Associated Coal, which would give the company control of over 50% of the high-volatile coal production market (CO 9/19/96 p.6).

In September 1996, A. T. Massey Coal purchased the Eagle Nest mine from BethEnergy Mines, including its longwall operation, mineral rights, and a prep plant and load-out served by CSX Transportation (CO 9/9/96 p.1). Massey then closed the mine and issued WARN notices to all 350 of its employees, but was planning to reopen it shortly and hire laid-off union miners (CO 9/9/96 p.1). Around the same time, Massey also applied for a permit to open a surface mine on property near Twilight, West Virginia, some of which overlies Eagle Nest's reserves (CO 9/16/96 p.2). As a result of the sale, Bethlehem Steel now has only one remaining coal property, High Power Mountain (HPM) in Nicholas County, West Virginia, which produces around 1 million tons of steam coal per year (CO 9/9/96 p.1).

A. T. Massey agreed to assume all of Eagle Nest's obligations under the 1993 National Bituminous Wage Agreement (CO 9/9/96 p.8). At the time, however, it was unclear as to whether Massey would also have to assume obligations under the Memorandum of Understanding Regarding Job Opportunities, or the "job rights MOU," under which a parent company and its non-union affiliates must hire three of five new workers from panels of laid-off union miners. Adhering to this standard would increase the chances that the UMW might eventually win representation at Massey's non-union operations (CO 9/9/96 p.8). A. T. Massey is a non-union company that has long resisted UMW organization efforts at its facilities (CO 9/9/96 p.8).

Updated: May 1997

Status: Open/Using

Federal No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Monongalia

CORPORATE INFORMATION

Current Owner: Eastern Assoc. Coal

Parent Company: Peabody Holding Co., Hanson PLC

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: N.D. Gallagher, Mine Manager

Phone Number: 304-449-1911

Mailing Address: Rt.1, Box 144

City: Fairview

State: WV

ZIP: 26570

GENERAL INFORMATION

Number of Employees at Mine: 503

Mining Method: Longwall

Year of Initial Production: 1968

Primary Coal Use: Steam

Mine Life Expectancy (years): 16

Sulfur Content of Coal Produced: 2.17% - 2.79%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,300

Depth to Seam (ft): 1,075

Seam Thickness (ft): 8.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.3	4.1	4.3	4.6
Estimated Total Methane Liberated (million cf/day):	12.3	10.7	13.8	14.3
Emissions from Ventilation Systems:	7.4	6.4	8.3	8.6
Estimated Methane Drained:	4.9	4.3	5.5	5.7
Estimated Specific Emissions (cf/ton):	3,433	957	1,187	1,142

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Federal No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.93	1.40
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	7.4%	11.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.7%	2.6%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	34.4	137.5
Mine Electricity Demand:	26.6	110.0
Prep Plant Electricity Demand:	7.8	27.5
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	21.7	190.2
Assuming 60% Recovery Efficiency: ¹	32.6	285.4

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	2.1
Assuming 60% Recovery Efficiency (Bcf): ¹	3.1
Description of Surrounding Terrain:	Open Low Mountains/High Hills
Transmission Pipeline in County?:	Yes
Owner of Nearest Pipeline:	Consolidated Natural Gas Supply Co. (CNG)
Distance to Pipeline (miles):	0.9
Pipeline Diameter (inches):	10.0
Owner of Next Nearest Pipeline:	NA
Distance to Next Nearest Pipeline (miles):	NA
Pipeline Diameter (inches):	NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Rivesville

Distance to Plant (miles): 10.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Pharmaceuticals, chemicals, apparel, and glass manufacturing; hospitals, university, and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Federal No. 2 (continued)

Summary of Recent News

Eastern Associated Coal Corporation (EACC) owns the Federal No. 2 mine, which opened in 1968. EACC owns/manages five business units comprised of six mines and related facilities in West Virginia, one of which is the Federal No. 2 Business Unit, formerly the Northern Operations Business Unit. EACC is a subsidiary of Peabody Holding Company, Inc., the largest private-sector coal producer. Peabody, in turn, is a wholly-owned unit of The Energy Group, a diversified international energy group headquartered in Britain. As of July, 1997, PacifiCorp, a Portland, Oregon utility was near an agreement to acquire The Energy Group for \$US 6 billion in cash. PacifiCorp, a top operator of coal mines and coal-based power plants in the United States, said one of the most attractive elements of the acquisition is the opportunity to combine forces with Peabody Coal (Coal Age, 1997).

Federal No. 2 has been recognized consistently for its safety achievements. Federal No. 2 received the EACC's President's Award in 1991, 1992, and 1993 for the lowest incidence rate for underground operations (Coal 11/94). In 1995, Federal No. 2 received the Mountain Guardian Safety Award, sponsored by the West Virginia Office of Mines, Health & Training and the West Virginia Mining & Reclamation Association, in recognition for its safety achievements (Coal 3/95). Federal No. 2 also is recognized for its top-rated mine rescue teams. At the 1996 National Mine Rescue, First Aid, EMT, and Bench Contest, a team from Federal No. 2 placed third in the combination first aid and rescue and fifth in first aid (EACC News Release 10/31/95).

Methane is currently being recovered, for sale, from the Federal No. 2 mine. Additional information on this methane recovery project is included in the section on existing methane recovery projects.

Sales & Supply

EACC's Federal No. 2 mine has secured several supply contracts since September 1994. Peabody COALSALES, a subsidiary of Peabody, secured a 10-year contract (starting in Jan. 1995) with Cincinnati Gas & Electric (CG&E) to supply about 1 million tons per year from Federal No. 2. The coal, which consists of 13,300 Btu/lb, 4.3 lbs/mmBtu of SO₂, and 8% dry ash, will be burned at CG&E's East Bend station (CW 10/17/96, CO 10/17/94, Coal 11/94). In addition, Peabody's Federal No. 2 mine was on CG&E's short list of potential suppliers to supply 300,000 to 1 million tons/year of coal to be delivered over 2-3 years beginning in 1996 (CW 6/5/95, CO 5/29/95).

In 1995, Peabody signed a two year contract with New York State Electric & Gas (NYSE&G) to supply an undisclosed amount of 13,000 Btu/lb, 2.12 percent sulfur, 7 percent ash from Federal No. 2's Pittsburgh No. 8 seam. Most of the coal is designated for NYSE&G's Goudey and Greenridge plants, but some might also be used at Kintigh station (CW 1/9/95). Also in 1995, Peabody's EACC signed a 2-3 year contract to supply coal to Ontario Hydro's Lambton power station from its Federal No. 2 mine (CW 4/3/95). Under a two year contract with Baltimore Gas & Electric, Federal No. 2 will supply Crane's station with 200,000 tons annually (CW 1/1/96).

Rochester (NY) Gas & Electric purchased an undisclosed portion of 150,000 tons of coal solicitation from Federal No. 2 (CW 6/5/95).

Keystone power plant bought spot coal from Federal No. 2 in August 1995 (CW 8/14/95).

Monongahela Power bought spot coal from the Federal No. 2 mine in September 1995 for \$23.41/ton freight on board, or 109 cents/mmBtu for 12,300 Btu/lb, 2.3 percent sulfur with 9.6 percent ash (CW 6/10/96).

Updated: May 1997

Status: Closing/Using

Humphrey No. 7

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Monongalia

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: John Higgins, General Superintendent

Phone Number: 304-879-5912

Mailing Address: P.O. Box 100

City: Osage

State: WV

ZIP: 26543

GENERAL INFORMATION

Number of Employees at Mine: 372

Mining Method: Longwall

Year of Initial Production: 1957

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 2.10% - 2.25%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 700

Seam Thickness (ft): 7.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.3	3.3	3.1	3.3
Estimated Total Methane Liberated (million cf/day):	7.0	6.2	7.8	7.7
Emissions from Ventilation Systems:	4.2	3.7	4.7	4.6
Estimated Methane Drained:	2.8	2.5	3.1	3.1
Estimated Specific Emissions (cf/ton):	1,930	693	919	850

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Humphrey No. 7 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.50	0.75
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	5.6%	8.4%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.3%	1.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	24.7	98.8
Mine Electricity Demand:	19.1	79.0
Prep Plant Electricity Demand:	5.6	19.8
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	11.6	101.8
Assuming 60% Recovery Efficiency: ¹	17.4	152.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.1
Assuming 60% Recovery Efficiency (Bcf): ¹	1.7
Description of Surrounding Terrain: Open Low Mountains/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)	
Distance to Pipeline (miles): 0.2	Pipeline Diameter (inches): 8.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Fort Martin

Distance to Plant (miles): 6.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Pharmaceuticals, chemicals, apparel, and glass manufacturing; hospitals, university, and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Humphrey No. 7 (continued)

Summary of Recent News

The Humphrey mine is owned by CONSOL. The mine is located in Monongalia County, West Virginia and produces high-sulfur coal. With a reduced market for high-sulfur coal as a result of new clean air laws, the Humphrey mine was targeted for closure. As of February 1997, the mine was still open thereby outlasting its neighboring high-sulfur mines, the Arkwright No. 1 and Osage No. 3 mines, both of which have been closed. Humphrey, however, will probably be closed in mid-1997 as a result of a depletion of economic reserves (CO 12/23/96).

In late 1994, the UMWA District 31 launched a public effort to save CONSOL's Osage No. 3, Arkwright, and Humphrey mines from being closed. All three mines employed UMW members and produced high-sulfur coal, which was seeing a rapid market decline as a result of new clean-air laws (CO 9/5/94).

To save the Arkwright, Osage and Humphrey mines from closure, the UMW embarked on a number of tactics including:

- asking the West Virginia governor to authorize the purchase of SO₂ emission credits, which would be used to compensate utilities that burn coal from those mines. The union's argument was that keeping the mines operational would be cheaper for the state in the long run than providing welfare and other social benefits to miners and their families who would be affected if the mines were closed (CO 10/17/94).
- discussing an employee buyout of the Osage, Humphrey and Arkwright mines from CONSOL. No firm commitments were made by either CONSOL or the UMWA (CO 2/13/95).

By early 1995, the probability of Humphrey being closed looked less remote because the UMW indicated that CONSOL was interested in buying a neighboring block of coal from Cyprus Amax, which would keep Humphrey going until 2008. The block of coal is known as the Emerald East reserve, which is just to the north of Humphrey (CO 2/20/95). CONSOL, meanwhile, had rarely commented on its long-term plans for Humphrey, only indicating that Humphrey would probably close in 1997 (CO 9/5/94; CO 7/24/95).

In the fall of 1996, two WARN notices were issued indicating that workers would be laid off in December 1996 as a precursor to the closing of the mine. On December 7, 1996, CONSOL laid off 146 people at the Humphrey mine (CO 9/23/96). CONSOL planned to lay-off an additional 20 people during the 14-day period beginning April 2, 1997 (CO 2/17/97). Although no firm date has been announced by CONSOL for closure of the mine, speculation is that the mine will be closed in mid-1997 (CO 12/23/96). In March 1997, it was reported that CONSOL was aiming to have the mine closed by June 1997. An example of this commitment was the issuing of WARN notices on March 21, 1997. The notices stated that 244 persons would be laid off over a 14-day period beginning May 23 (CO 3/31/97; Coal Age, May 1997).

But in April 1997, it was reported that CONSOL wanted to purchase a 250-acre coal reserve area, which would insure that the Humphrey mine would continue operating for another three to seven years. Although CONSOL is not, at this time, committing to the continuation of operations at Humphrey, they are clearly interested in this new development. CONSOL would purchase the additional 250-acres as a judicial sale. Because this judicial sale would be the first one for the county it is unlikely that the sale would be approved by the time Humphrey is slated to close (CO 4/14/97).

Sales & Supply

Humphrey's major customer is the Allegheny Power System.

Updated: May 1997

Status: Open/Using

Loveridge No. 22

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Marion

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: John Straface, Mine Superintendent

Phone Number: 304-662-6107

Mailing Address: P.O. Box 40

City: Fairview

State: WV

ZIP: 26570

GENERAL INFORMATION

Number of Employees at Mine: 87

Mining Method: Longwall

Year of Initial Production: 1953

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 2.54% - 2.82%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,300

Depth to Seam (ft): 1,250

Seam Thickness (ft): 7.8

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	3.1	2.7	3.1
Estimated Total Methane Liberated (million cf/day):	6.0	6.7	7.3	7.3
Emissions from Ventilation Systems:	3.6	4.0	4.4	4.4
Estimated Methane Drained:	2.4	2.7	2.9	2.9
Estimated Specific Emissions (cf/ton):	1,288	794	998	875

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Loveridge No. 22 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.48	0.71
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	5.7%	8.6%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.3%	2.0%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	22.9	91.7
Mine Electricity Demand:	17.7	73.4
Prep Plant Electricity Demand:	5.2	18.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	11.1	97.3
Assuming 60% Recovery Efficiency: ¹	16.7	146.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	1.1
Assuming 60% Recovery Efficiency (Bcf): ¹	1.6
Description of Surrounding Terrain: Open Low Mountains/High Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)	
Distance to Pipeline (miles): 0.9	Pipeline Diameter (inches): 10.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Rivesville

Distance to Plant (miles): 10.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Lighting products, temperature control equipment, hospital and other municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Loveridge No. 22 (continued)

Summary of Recent News

The Loveridge mine is owned by CONSOL. The mine is located in Marion County, West Virginia and produces high-sulfur coal.

In April 1995, the Loveridge mine was temporarily idled as a result of reduced sales. The reduced sales were a result of low utility burns, and thus led to high stock-piles of coal. However, in July 1995, the Loveridge mine resumed active production (CO 7/24/95). Earlier, in January 1994, CONSOL had indicated that because of the uncertain market for high-sulfur coal the Loveridge mine would probably operate sporadically over the coming years, so there was always a fear amongst the UMW that the mine might suffer the same fate as other high-sulfur coal-producing mines, like the Arkwright mine, which was closed in late 1995 (CO 1/10/94).

Those fears, however, were assuaged the following year when CONSOL installed a new, state-of-the-art longwall at the mine, hoping that the increased production from the mine would lead to lower mine costs and increased competitiveness of Loveridge coal. Additionally, CONSOL expected that the increased production would help offset some of the production lost as a result of the pending closure of the Humphrey mine (CO 8/26/96).

Sales & Supply

Loveridge customers include Ontario Hydro, Rochester Gas & Electric, and New York State Electric & Gas (NYSE&G). In October 1994, NYSE&G bought 168,000 tons of contract coal from CONSOL's Loveridge and Bailey mines. In 1995, Rochester Gas & Electric bought 150,000 tons of coal from various CONSOL mines. The coal was supplied by the Blacksville No. 2, Bailey and Loveridge mines. In May 1996, NYSE&G bought 144,000 tons of contract coal from CONSOL's Loveridge mine. In September 1996, NYSE&G bought 24,000 tons of contract coal from CONSOL's Loveridge mine (CW 10/3/94; CW 6/5/95; CW 4/29/96; CW 8/26/96).

Updated: May 1997

Status: Operating

Maple Meadow No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Beckley

County: Raleigh

CORPORATE INFORMATION

Current Owner: Maple Meadow Mining

Parent Company: Cyprus Amax

Previous Owner(s): Algoma Steel/Cannelton Coal

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Keith Sinsel

Phone Number: 304-348-0500

Mailing Address: General Delivery

City: Fairdale

State: WV

ZIP: 25839

GENERAL INFORMATION

Number of Employees at Mine: 303

Mining Method: Room & Pillar

Year of Initial Production: 1975

Primary Coal Use: Metallurgical

Mine Life Expectancy (years): 8

Sulfur Content of Coal Produced: 0.80% - 1.25%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 15,000

Depth to Seam (ft): 735

Seam Thickness (ft): NA

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.2	1.0	1.1	1.5
Estimated Total Methane Liberated (million cf/day):	3.6	1.9	2.8	3.9
Emissions from Ventilation Systems:	3.6	1.9	2.8	3.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	1,075	661	903	945

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Maple Meadow No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.25	0.38
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	5.5%	8.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	1.3%	1.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	11.3	45.2
Mine Electricity Demand:	8.7	36.2
Prep Plant Electricity Demand:	2.6	9.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	5.9	51.8
Assuming 60% Recovery Efficiency: ¹	8.9	77.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.6
Assuming 60% Recovery Efficiency (Bcf): ¹	0.9
Description of Surrounding Terrain: Low Mountains	
Transmission Pipeline in County?: No	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 3.0	Pipeline Diameter (inches): 10.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Maple Meadow No. 1 (continued)

Summary of Recent News

The Maple Meadow mine, located in Raleigh County, West Virginia, began production in 1975. Maple Meadow was purchased by AMAX from Algoma Steel in 1991, and has since become a subsidiary of the newly formed Cyprus Amax Minerals Company (CN 5/31/93). Maple Meadow is a room and pillar mine, producing high-grade, low-volatile metallurgical coal.

Sales & Supply

Maple Meadow's past customers have included Algoma Steel Corp. Ltd. of Ontario and LTV Steel Co., Inc. of Cleveland. Spot market customers have included New England Power and various international companies (Coal 10/92 p.33).

In August 1995, AK steel purchased 7,000 tons of coal from the Maple Meadow mine in anticipation of shortfalls from Maben Energy resulting from contract disputes (CO 8/7/95 p.6, CO 1/15/96 p.7).

In May 1996, Cyprus/AMAX apparently signed a rail contract with Geneva Steel in Utah for coal from Maple Meadow. The contract began March 1, 1996, and expires in February 1997, with an estimated tonnage of 120,000 to 150,000 tons/year. Geneva Steel had previously been receiving its coal from Lady H Coal in West Virginia (CO 5/13/96 p.4).

Updated: May 1997

Status: Operating

McElroy

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Marshall

CORPORATE INFORMATION

Current Owner: McElroy Coal Co./Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Paul Kvederis, Manager, Public Relations

Phone Number: 304-845-3473

Mailing Address: R.D. 4, Box 425

City: Moundsville

State: WV

ZIP: 26041

GENERAL INFORMATION

Number of Employees at Mine: 322

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 3.98% - 4.42%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,300

Depth to Seam (ft): 750

Seam Thickness (ft): 5.0 - 5.4

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.8	4.1	4.1	4.3
Estimated Total Methane Liberated (million cf/day):	2.0	2.7	3.5	3.4
Emissions from Ventilation Systems:	2.0	2.7	3.5	3.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	411	241	314	288

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

McElroy (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.22	0.33
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.0%	3.1%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.5%	0.7%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Wheeling Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	32.3	129.1
Mine Electricity Demand:	24.9	103.2
Prep Plant Electricity Demand:	7.3	25.8
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	5.2	45.1
Assuming 60% Recovery Efficiency: ¹	7.7	67.7

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.5
Assuming 60% Recovery Efficiency (Bcf): ¹	0.7
Description of Surrounding Terrain: High Hills/Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 0.0	Pipeline Diameter (inches): 10.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Ohio Power Kammer Plant

Distance to Plant (miles): 10.0 Boiler Capacity (MW): 237.0

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

McElroy (continued)

Summary of Recent News

The McElroy mine is owned by Quarto Mining, a subsidiary of CONSOL. The mine is located in Marshall County, WV and is a high-sulfur coal producer.

In late 1994, American Electric Power (AEP), the U.S. EPA, and the Justice Department reached an agreement on acceptable levels of emissions from AEP's Kammer Plant. The Kammer plant is owned by Ohio Power, a wholly owned subsidiary of AEP. As part of the agreement, AEP ceased burning high-sulfur coal at the Kammer plant, as of January 1, 1995. The Kammer plant received much of its coal from the McElroy mine. Ohio Power replaced the McElroy coal temporarily with a slightly lower-sulfur, although still a high-sulfur coal mined at Shoemaker (CO 11/21/94). Eventually the agreement called for even lower emissions by burning mid-sulfur coals. This coal would be supplied by the Bailey mine. The trigger date for the lower emissions would be September 1, 1995. AEP, however, is opposed to this latter part of the agreement and is fighting to maintain the right to burn higher-sulfur coals at the Kammer plant.

Despite the loss of the AEP contract, CONSOL maintained that its McElroy mine will not be seriously affected and will not be closed. CONSOL has pursued additional markets for McElroy coal (CO 11/28/94). In 1995, McElroy was the third largest CONSOL producing mine, producing 4.1 million tons for that year (Keystone, 1997).

Sales & Supply

Purchasers of McElroy's high-sulfur coal include Monongahela Power and Cincinnati Gas & Electric. Monongahela Power signed two separate spot contracts with CONSOL, one for three months and one for nine months. Both started in April 1996. The spot sale covered coal from the McElroy and Shoemaker mines. (CW 9/6/96). In December 1995, McElroy and Shoemaker jointly shipped 209,515 tons of coal to Monongahela Power (CW 6/10/96). In mid-1996, Cincinnati Gas & Electric placed orders for a total of 898,000 tons of high-sulfur coal. Suppliers of the coal were the Powhatan No. 4, Powhatan No. 6 and McElroy mines (CO 5/13/96).

Updated: May 1997

Status: Open/Using

Pinnacle No. 50

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Pocahontas No. 3

County: Wyoming

CORPORATE INFORMATION

Current Owner: U.S. Steel Mining Co., Inc.

Parent Company: USX Corp.

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: Gary No. 50

MINE ADDRESS

Contact Name: J.R. Vilseck, Jr., Division Manager, Mine Operations

Phone Number: 304-732-5200

Mailing Address: P.O. Box 338

City: Pineville

State: WV

ZIP: 24874

GENERAL INFORMATION

Number of Employees at Mine: 550

Mining Method: Longwall

Year of Initial Production: 1971

Primary Coal Use: Metallurgical

Mine Life Expectancy (years): 18

Sulfur Content of Coal Produced: 0.75%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 14,810

Depth to Seam (ft): 575

Seam Thickness (ft): 4.2

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	3.7	4.4	5.1	4.1
Estimated Total Methane Liberated (million cf/day):	18.2	18.6	23.0	21.4
Emissions from Ventilation Systems:	9.1	9.3	11.5	10.7
Estimated Methane Drained:	9.1	9.3	11.5	10.7
Estimated Specific Emissions (cf/ton):	1,784	1,536	1,638	1,922

Estimated Current Drainage Efficiency: 50%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Pinnacle No. 50 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	1.39	2.08
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	11.3%	16.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	2.6%	3.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	30.5	121.9
Mine Electricity Demand:	23.6	97.5
Prep Plant Electricity Demand:	6.9	24.4
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	32.4	284.0
Assuming 60% Recovery Efficiency: ¹	48.6	426.1

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	3.1
Assuming 60% Recovery Efficiency (Bcf): ¹	4.7
Description of Surrounding Terrain: Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line	
Distance to Pipeline (miles): 0.0	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: Cabot	
Distance to Next Nearest Pipeline (miles): 0.5	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Mining equipment manufacturing, quarries, municipal buildings.

¹ Drainage system already in use; current drainage efficiency shown on previous page.

Pinnacle No. 50 (continued)

Summary of Recent News

The Pinnacle No. 50 mine, which is located in West Virginia, is also known as the Gary No. 50 mine. Pinnacle No. 50 is one of two mining complexes owned and operated by U.S. Steel Mining Company. The other is Oak Grove, which is located in Alabama. Pinnacle No. 50 is longwall equipped and mines low-volatile metallurgical coal from the Pocahontas No. 3 seam. Twenty percent of the coal produced is used by U.S. Steel in its steel production operations with the remaining coal being sold to domestic and international clients (CO 10/10/94).

The latter part of 1994 saw a number of capital improvements occurring at Pinnacle No. 50. In September 1994, U.S. Steel Mining outlined plans to increase production from Gary No. 50 to 5 million tons in 1995. This would be achieved by using an alignment of two longwalls and five continuous miners. The increased production would account for the lost production of the closed, neighboring Shawnee mine. In mid-September 1994, U.S. Steel Mining shut the Shawnee longwall and closed the mine. The company, then, made an underground cut-through between the Pinnacle, Gary No. 50 and Shawnee mines, in effect, allowing them access to unmined Shawnee reserves. The cut-through also allowed the company to have access to the Pinnacle prep plant, which is closer to the entry to the Shawnee mine than to the entry to the Pinnacle No. 50 mine (CO 10/10/94).

Despite production increases, the UMW predicted layoffs of 270 UMW-represented workers by the end of 1994. A precursor to the layoffs came when U.S. Steel Mining laid off 60 workers in the latter half of 1994 (CO 10/10/94).

In October 1996, longwall operations were halted as a result of the longwall hitting a roll or seam pitch. Initially, U.S. Steel Mining tried to resolve the problem by working through the pitch, but eventually decided to move the longwall to another panel. Longwall operations resumed on November 4, 1996 after three weeks of downtime. The longwall problems lead analysts to speculate that the mine had almost exhausted the reserves that could be mined with a longwall. The West Virginia Department of Environmental Protection (DEP), however, refuted that speculation saying that U.S. Steel Mining's mine plans indicate that a number of longwall panels are planned. The West Virginia DEP further stated that general projections are that total reserves will last another 12 to 15 years (CO 11/11/96).

As a result of the shutdown of the longwall, there were signs that U.S. Steel Mining had to declare force majeure on some of its coal contracts due to production problems. U.S. Steel Mining did not offer any comment on the situation plaguing coal production at Pinnacle No. 50 (CO 11/11/96). Any purchases or missed sales of metallurgical coal as a result of the longwall shutdown was costly for U.S. Steel. Supplies of mid-volatile and high-volatile metallurgical coals remained very tight during the period of the shutdown, forcing spot coal prices to remain high (CO 10/21/96).

Pinnacle No. 50 currently has a methane recovery and utilization project. Please see discussion of current projects for more information.

Updated: May 1997

Status: Operating

Robinson Run No. 95

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Harrison

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: No. 95

MINE ADDRESS

Contact Name: Thomas Simpson, General Superintendent

Phone Number: 304-795-4421

Mailing Address: P.O. Box 326

City: Shinnston

State: WV

ZIP: 26431

GENERAL INFORMATION

Number of Employees at Mine: 421

Mining Method: Longwall

Year of Initial Production: 1968

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 2.95% - 3.14%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,100

Depth to Seam (ft): 700

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.3	3.3	3.7	4.2
Estimated Total Methane Liberated (million cf/day):	3.2	2.7	4.0	4.5
Emissions from Ventilation Systems:	1.9	1.6	2.4	2.7
Estimated Methane Drained:	1.3	1.1	1.6	1.8
Estimated Specific Emissions (cf/ton):	872	292	398	390

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Robinson Run No. 95 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.29	0.44
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	2.6%	3.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.6%	0.9%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	31.6	126.3
Mine Electricity Demand:	24.4	101.1
Prep Plant Electricity Demand:	7.2	25.3
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	6.8	59.7
Assuming 60% Recovery Efficiency: ¹	10.2	89.6

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.7
Assuming 60% Recovery Efficiency (Bcf): ¹	1.0
Description of Surrounding Terrain: Open Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Equitable Gas	
Distance to Pipeline (miles): 0.2	Pipeline Diameter (inches): 10.0
Owner of Next Nearest Pipeline: Consolidated Gas Supply	
Distance to Next Nearest Pipeline (miles): 3.0	Pipeline Diameter (inches): 12.0

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Harrison

Distance to Plant (miles): 2.0

Boiler Capacity (MW): 2,052.0

Nearby Industrial/Institutional Facilities?: Aircraft, glass, and casket manufacturing; FBI facility, shopping malls, and municipal buildings.

¹ Drainage system already in use; estimated current drainage efficiency shown on previous page.

Robinson Run No. 95 (continued)

Summary of Recent News

The Robinson Run No. 95 mine is owned by Consolidation Coal Company, a wholly owned subsidiary of CONSOL. The mine is located in Harrison County, West Virginia, and is longwall equipped. The mine produces high-sulfur coal.

The Consolidation Coal Company installed a longwall at the mine in 1994. The longwall was expected to increase productivity, although the company declined to say by how much. Beyond an increase in productivity, the installation also means a longer life-span for the Robinson Run No. 95 mine and assuages any fears that the mine might suffer the same fate of other CONSOL, high-sulfur mines, like Arkwright, which was closed in late 1995 (CW 8/26/96). In 1995, Robinson Run No. 95 was the sixth largest producing CONSOL underground mine (Keystone, 1997).

On December 16, 1995, CONSOL laid off about 75 workers saying that the job cuts were a result of the completion of non-mining projects at Robinson Run No. 95. The layoff covered about 20% of the workforce (CO 12/25/95).

Sales & Supply

The main purchasers of Robinson Run No. 95 coal are Seminole Electric Cooperative (FL) and the Allegheny Power System (CW 10/14/96; CW 4/17/95). In December 1995, Robinson Run No. 95 shipped 63,000 tons of high-sulfur coal to Seminole Electric Cooperative. Under a separate spot award Robinson Run No. 95 sold 155,000 tons of coal to Seminole Electric Cooperative. The coal was delivered from October 1995 through March 1996 (CO 10/23/95; CO 4/15/96). In late 1995, Seminole Electric Cooperative awarded the Robinson Run No. 95 mine a contract to ship 144,000 tons of high-sulfur coal from January through May 1996 with an option to buy another 288,000 tons during 1996 (CO 12/18/96). Seminole exercised that option buying 144,000 tons for delivery from May through September 1996 and buying an additional 144,000 tons for delivery starting September 1996 (CO 9/16/96; CO 5/13/96). The mine will provide 180,000 tons of high-sulfur coal to Seminole Electric Cooperative during the first half of 1997 (CO 10/14/96).

Updated: May 1997

Status: Operating

Sentinel

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Kittaning (L)

County: Barbour

CORPORATE INFORMATION

Current Owner: Philippi Development Inc

Parent Company: Anker Energy

Previous Owner(s): Jones & Laughlin Steel and Old Ben Coal

Previous or Alternate Name of Mine: Kitt No. 1 and Diamond No. 1

MINE ADDRESS

Contact Name: Gary McCauley, President

Phone Number: 304-457-1895

Mailing Address: Rt. 3, Box 146

City: Philippi

State: WV

ZIP: 26416

GENERAL INFORMATION

Number of Employees at Mine: 191

Mining Method: Room & Pillar

Year of Initial Production: 1975

Primary Coal Use: Steam/Metallurgical

Mine Life Expectancy (years): 16

Sulfur Content of Coal Produced: 0.96% - 1.34%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 13,075

Depth to Seam (ft): 425

Seam Thickness (ft): 5.0

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.2	1.3	1.4	1.8
Estimated Total Methane Liberated (million cf/day):	1.9	2.2	2.0	2.4
Emissions from Ventilation Systems:	1.9	2.2	2.0	2.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	567	618	536	490

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Sentinel (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.16	0.23
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	3.2%	4.9%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.7%	1.1%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Philippi Municipal Electric

Parent Corporation of Utility: None

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	13.4	53.7
Mine Electricity Demand:	10.4	42.9
Prep Plant Electricity Demand:	3.0	10.7
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	3.6	31.9
Assuming 60% Recovery Efficiency: ¹	5.5	47.8

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.4
Assuming 60% Recovery Efficiency (Bcf): ¹	0.5
Description of Surrounding Terrain: Open Low Mountains	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Hope Gas	
Distance to Pipeline (miles): 0.5	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Harrison

Distance to Plant (miles): 24.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Sentinel (continued)

Summary of Recent News

The Sentinel mine was initially known as the Kitt mine and then as the Black Diamond mine. The now defunct Republic Steel opened the mine in 1975 as a longwall operation. However, the company never achieved targeted production levels from the longwall and in 1982 sold the mine to Old Ben. Old Ben also tried to operate the mine as a longwall, but was unsuccessful. Old Ben subsequently sold the mine to a contractor who removed and sold the longwall equipment. In 1987, Anker Energy purchased the mine and subsequently formed Philippi Development, Inc. to operate the mine. Sentinel is non-union and employs 191 workers and 53 contractors (Coal 11/95).

Since acquiring the mine, Philippi has made capital investments in equipment by purchasing high-output continuous miners and mobile roof supports (MRSs). Philippi has also upgraded the mine's preparation plant. In 1993, one side of the plant was upgraded by replacing Diester tables with heavy-media cyclones and spirals (Coal 11/95).

After years as a longwall operation, Philippi now uses only continuous miners at Sentinel. The mine's 1994 production reached 2 million raw tons of coal using only continuous miners (Coal 11/95). Sentinel is usually able to produce 1.5 million tons of clean coal annually from three active continuous miner units operating two shifts a day, seven days a week (CO 4/3/95). The mine has a total of five continuous miner sections: two sections work on development, one section mines coal from pillars existing in the developed panels, one section stays idle as a spare, and one section remains in a transient mode (Coal 11/95). Currently, the mine averages 1,000 tons per unit shift. Once cleaned, the finished product is a steam coal with specifications of 1.25% sulfur, 8.25% ash, and 13,000 Btu per lb. The clean coal is stored in a 100,000-ton open stockpile. Operating at a cost of \$50 per ton of coal purchased, this mine is now the lowest cost, most efficient mine in Northern West Virginia outside of the large Pittsburgh seam mines (CO 4/3/95). The mine has rail access to the CSX line and uses 1,200-ton-per-hour unit train loadouts (Coal 11/95).

Sentinel produces coal from the Lower Kittanning seam. The coal bed averages 60 inches and the overburden depth is 450 feet. Sentinel has had to face some challenging mine conditions. One problem is stresses that were created in the massive sandstone roof by previously mined longwall panels (Coal 11/95). Another problem is that the seam dips slightly and sometimes the bottom is relatively soft. The mine also has some problems with thinning seams on the development side and squeezes on the solid side of the panels when the pillaring section retreats.

Sentinel has been considered for a methane recovery project in the past. In 1993, New England Electric System (NEES) selected the Sentinel mine to be the site of its test project on coal mine methane recovery. NEES was interested in the possibility of using coal mine methane entrapment to offset the greenhouse gases emitted at its power plants. Unfortunately, the results of the study showed that due to the poor reservoir quality of the Lower Kittanning coal seam, the project was not economically viable at the time (NYT 1/10/93).

Sales & Supply

Philippi sells most of Sentinel's coal to New England Power. The Sentinel mine will also supply Baltimore Gas & Electric's Crane plant with 300,000 tons per year from January 1, 1996, to December 31, 1997 (CO 1/8/96). This contract for the Sentinel mine is a partnership between Anker Energy and Courtney Foos. In addition to these utility customers, about 5% to 15% of Sentinel's coal goes to metallurgical coal markets (Coal 11/95).

Sales for Anker Energy -- Philippi's parent company -- have been growing at an annual rate of 20 percent. Anker now owns or controls between 300 million and 400 million tons of economically recoverable reserves (CO 4/3/95). According to John Faltis, president and part owner of Anker Group Inc., Anker is striving to become the largest producer of low-sulfur coal in northern Appalachia. The company currently produces 2 million tons annually of compliance coal and intends to add an additional 1 million tons annually. The balance of the company's production is less than 1.5% sulfur (CO 4/3/95).

Updated: May 1997

Status: Operating

Shoemaker

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Marshall

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Coal Group (Du Pont/Rheinbraun AG)

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: E.R. Pride, II, General Superintendent

Phone Number: 304-242-8544

Mailing Address: Big Wheeling Creek Rd.

City: Bethlehem

State: WV

ZIP: 26041

GENERAL INFORMATION

Number of Employees at Mine: 365

Mining Method: Longwall

Year of Initial Production: 1968

Primary Coal Use: Steam

Mine Life Expectancy (years): NA

Sulfur Content of Coal Produced: 4.00% - 4.22%

Prep Plant Located On Site?: Yes

BTUs/lb of Coal Produced: 12,500

Depth to Seam (ft): 650

Seam Thickness (ft): 5.0 - 5.5

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.4	1.8	3.8	4.4
Estimated Total Methane Liberated (million cf/day):	2.0	1.2	2.5	2.5
Emissions from Ventilation Systems:	2.0	1.2	2.5	2.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	510	249	239	207

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Shoemaker (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.16	0.24
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	1.4%	2.2%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.3%	0.5%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Wheeling Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	33.1	132.4
Mine Electricity Demand:	25.6	106.0
Prep Plant Electricity Demand:	7.5	26.5
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	3.8	33.2
Assuming 60% Recovery Efficiency: ¹	5.7	49.8

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.4
Assuming 60% Recovery Efficiency (Bcf): ¹	0.5
Description of Surrounding Terrain: High Hills/Hills	
Transmission Pipeline in County?: Yes	
Owner of Nearest Pipeline: Columbia Gas Transmission	
Distance to Pipeline (miles): 0.2	Pipeline Diameter (inches): 10.0
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: Rivesville

Distance to Plant (miles): 13.0

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Shoemaker (continued)

Summary of Recent News

The Shoemaker mine is owned and operated by Consolidation Coal Company, a wholly owned subsidiary of CONSOL. The mine, which is located in Marshall County, WV, produces high-sulfur steam coal. The mine is longwall-equipped.

American Electric Power's subsidiary Ohio Power is the major purchaser of Shoemaker's coal (CO 5/15/95 p.3). Most of the coal mined at Shoemaker is delivered to the utility's Kammer plant. But newly promulgated clean air laws are currently threatening the productivity and viability of the mine. Under the new Clean Air Act, the U.S. EPA imposed a sulfur dioxide emission limit of 2.7lb/mmBTU for the Kammer plant. These new emission limits had to be met by Ohio Power by May 1996, unless Ohio Power could prove that the higher emissions of sulfur dioxide currently produced by burning coal from Shoemaker did not substantially impair air quality in West Virginia (CW 6/3/96 p.3). Under the agreement, if Ohio Power was unable to prove this point the utility would have been mandated to meet the earlier stipulated limit by burning mid-sulfur and low-sulfur coals.

Since Shoemaker is a high-sulfur coal producer and since Ohio Power is Shoemaker's major customer, the loss of the Ohio Power contract could mean closure of the mine (CO 10/30/95 p.6). Because of the uncertainty surrounding the outcome of AEP's negotiations with the state of West Virginia and the U.S. EPA, in May 1995 CONSOL warned workers at the Shoemaker mine that they could be laid off indefinitely starting in July 1995 (CO 5/15/95 p.6).

AEP, however, is adamant that burning Shoemaker coal is not an environmental hazard and is hoping to prove that the 6.5 lbs of sulfur dioxide limit that the utility currently complies with does not harm ambient air quality in the state. The debate still continues, however, and AEP and the state of West Virginia are working on new air modeling information. The latest reports are that the Shoemaker mine will be able to supply coal to AEP's Kammer plant until early 1999 when the study is due to be completed (CO 7/15/96 p.3).

Sales & Supply

As mentioned previously, AEP's Ohio Power is the major purchaser of Shoemaker coal. Other purchasers include Kentucky Utilities and the Tennessee Valley Authority.

Beginning in October 1996, Shoemaker sold 20,000 tons of coal per month for 3 months to Big Rivers' plants (CW 10/28/96 p.6).

Shoemaker and McElroy together sold 74,134 and 48,592 tons of coal to Monongahela Power in May and June 1996 respectively (CW 9/16/96 p.8).

In early 1995, Kentucky Utilities signed a five year contract with Shoemaker in which the utility requested that the mine supply 2.1 million tons of high-sulfur coal over the life of the contract. The coal will be shipped via barge and will be delivered to the utility's scrubber equipped Ghent No.1 Unit (CO 5/1/95 p.1). In August 1995, as part of a separate spot market contract, Kentucky Utilities purchased 35,000 tons of coal from Shoemaker (CW 8/7/95). The utility also bought an additional 660,000 tons of spot coal, which will be supplied by Shoemaker and some Peabody mines. The coal was delivered from mid-1995 through mid-1996 to the utility's Ghent plant (CO 8/7/95 p.7).

Between October and December 1994, the Tennessee Valley Authority acquired 225,000 tons of coal from Shoemaker (CW 5/15/95).

Updated: May 1997

Status: Operating

Windsor

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh

County: Brooke

CORPORATE INFORMATION

Current Owner: Windsor Coal Co.

Parent Company: American Electric Power

Previous Owner(s): None in last five years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Joseph B. Matkovich, Mine Superintendent

Phone Number: 304-336-7203

Mailing Address: P.O. Box 39

City: West Liberty

State: WV

ZIP: 26074

GENERAL INFORMATION

Number of Employees at Mine: 213

Mining Method: Longwall

Year of Initial Production: NA

Primary Coal Use: Steam

Mine Life Expectancy (years): 31

Sulfur Content of Coal Produced: 2.73% - 3.69%

Prep Plant Located On Site?: No

BTUs/lb of Coal Produced: 12,295

Depth to Seam (ft): 500

Seam Thickness (ft): 5.0 - 5.8

PRODUCTION, VENTILATION, AND DRAINAGE DATA

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
Coal Production (million short tons/year):	1.7	1.2	1.1	1.4
Estimated Total Methane Liberated (million cf/day):	0.5	0.5	0.3	0.3
Emissions from Ventilation Systems:	0.5	0.5	0.3	0.3
Estimated Methane Drained:	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	108	151	104	76

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Windsor (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency ¹	
(Based on 1996 Data)	<u>40%</u>	<u>60%</u>
CO ₂ Equivalent of CH ₄ Emissions Reductions (mm tons):	0.02	0.03
CO ₂ Equivalent of CH ₄ Emissions Reductions/ CO ₂ Emissions from Coal Combustion:	0.5%	0.8%
BTU Value of Recovered Methane/ BTU Value of Coal Produced:	0.1%	0.2%

POWER GENERATION POTENTIAL

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	<u>MW</u>	<u>GWh/year</u>
Total Electricity Demand (1996 data):	8.3	34.5
Mine Electricity Demand:	8.3	34.5
Prep Plant Electricity Demand:	0.0	0.0
Potential Generating Capacity (1996 data)		
Assuming 40% Recovery Efficiency: ¹	0.5	4.0
Assuming 60% Recovery Efficiency: ¹	0.7	6.0

PIPELINE SALES POTENTIAL

Potential Annual Gas Sales (1996 data)	<u>Bcf</u>
Assuming 40% Recovery Efficiency (Bcf): ¹	0.0
Assuming 60% Recovery Efficiency (Bcf): ¹	0.1
Description of Surrounding Terrain: NA	
Transmission Pipeline in County?: NA	
Owner of Nearest Pipeline: NA	
Distance to Pipeline (miles): NA	Pipeline Diameter (inches): NA
Owner of Next Nearest Pipeline: NA	
Distance to Next Nearest Pipeline (miles): NA	Pipeline Diameter (inches): NA

OTHER UTILIZATION POSSIBILITIES

Name of Nearby Coal Fired Power Plant: None

Distance to Plant (miles): NA

Boiler Capacity (MW): NA

Nearby Industrial/Institutional Facilities?: Not yet researched.

¹ Drainage efficiency is projected; this mine currently does not have a drainage system.

Windsor (continued)

Summary of Recent News

The Windsor mine is located in Brooke County, West Virginia. Windsor produces high-sulfur steam coal with a specification of around 3.28% sulfur. The mine is operated by Windsor Coal Company, a subsidiary of Ohio Power Co. Ohio Power is a subsidiary of American Electric Power (AEP), which is based in Columbus, Ohio.

In an agreement signed in February 1995, Ohio Power extended an existing \$1.57 per mmBtu price cap on coal delivered to its Gavin power plant. The cap will now also cover coal shipped from AEP's Windsor underground mine to the Cardinal Unit 1 plant, and coal from the Muskingum surface mine that goes to the Muskingum River 1-4 complex. The cap will be in effect for the Windsor and Muskingum mines from June 1995 through November 1998, while the price cap on coal shipped to Gavin under the original plan lasts until 2009 (CO 3/6/95 p.1). The new agreement was forged in an effort to cap costs at the mines and to ensure that users would be protected against increasing costs once Phase I of the Clean Air Act commenced (CO 1/16/95 p.4). However, the Windsor mine may be closed anyway once Phase II begins in the year 2000, because AEP may switch the Cardinal Unit I plant to compliance coal (CO 3/6/95 p.1).

In an effort to further reduce costs, in August 1995 Windsor Coal Co. applied to the Securities and Exchange Commission for permission to sell its coal on the spot market. AEP said that revenues from the coal sales would go to reduce mining costs and would decrease the price of coal sold to Ohio Power (CW 8/7/95 p.6).

In early 1996, the Federal Energy Regulatory Commission (FERC) approved a bulk power agreement between Louisville Gas and Electric (LG&E) and Ohio Edison's Burger power plant. LG&E will provide around 1 million tons of high-sulfur coal from AEP's Windsor mine to Ohio Edison's Burger plant, located in Shadyside, Ohio. In return, Ohio Edison will sell 250-300 MW of electricity per month to LG&E Power Marketing (an LG&E affiliate) through 1996, at a price of around \$5/MWh (CW 3/4/96 p.3). Under the terms of the agreement, Ohio Edison can purchase any excess coal delivered to the Burger plant at a mutually agreed price, but will not reimburse LG&E for more than 15,000 excess tons (CO 5/13/96 p.4). Single source coal supply arrangements such as the one between LG&E and Ohio Edison are said to produce electricity at a lower cost, but are a substantial risk because the coal originates from just one large mine (CW 6/17/96 p.4).

In February 1996, AEP released the expected dates of closure for four of its affiliate mines; the Windsor complex will be closed in the year 2000, the first year of Phase II of the Clean Air Act (CO 2/19/96 p.5).

Sales & Supply

In a 1996 "tolling" agreement, the Windsor mine will supply around 1 million tons of coal to Ohio Edison's Burger power plant for Louisville Gas & Electric, in exchange for 250-300 MW of electricity, to be sold to LG&E Power Marketing (CO 5/13/96 p.4). The price of the coal from Windsor was \$18.79 per ton (FOB) for 3.0% sulfur coal, and \$17.08 for 3.50% sulfur coal (CW 5/20/96 p.6).

7. References

7. References

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References and Calculations Used in the Mine Profiles

Data Item	Sources	Calculations
Geographic Data (State, County, Basin, Coalbed)	USBM (1993)	
Corporate Information: Current Owner Previous Owner Parent Company	Past versions of Keystone Coal Manual and recent coal industry publications Past versions of Keystone Coal Manual and Coal Magazine Annual Longwall Surveys Past versions of Keystone Coal Manual and recent coal industry publications	
Phone/Address/Contact Information	Past versions of Keystone Coal Manual and EIA reports.	
General Information: Number of Employees Year of Initial Production Life Expectancy Sulfur Content Mining Method	Past versions of Keystone Coal Manual USBM (1973 and 1977); Past versions of Keystone Coal Manual and articles in coal industry publications Past versions of Keystone Coal Manual Past versions of Keystone Coal Manual Past versions of Keystone Coal Manual and Coal Magazine 1997	

Data Item	Sources	Calculations
	Longwall Survey	
Primary Use	Past versions of Keystone Coal Manual	
Production, Ventilation, and Drainage Data		
Coal Production	EIA Mine Production Reports (1993 - 1995); Individual state data (1996)	
Emissions from Ventilation Systems	MSHA (1993 - 1996)	
Estimated Methane Drained	The number of mines assumed to have drainage systems is based on calls to individual MSHA districts.	For those mines assumed to have drainage systems, drainage emissions are estimated by assuming that they are 40% of total liberation, unless otherwise noted.
Estimated Total Methane Liberated		Sum of "emissions from ventilation systems" and "estimated methane drained."
Degasification Information		
Drainage System Used	Based on calls to individual MSHA districts offices.	
Estimated Current Drainage Efficiency		Assumed to be 40% unless otherwise noted for mines where the drainage efficiency is known.
Energy and Environmental Value		
CO ₂ Equivalent of Methane Emissions Reductions (mm tons)	Global Warming Potential of Methane Compared to CO ₂ based on IPCC (1992). GWP is 21 over 100 years.	Estimated 1996 CH ₄ liberated (mmcf) x recovery efficiency x 19.2 g/cf x 21 g CO ₂ /1 g CH ₄ x 1 lb / 453.59 g x 1 ton / 2000 lbs
CO ₂ Equivalent of Methane Emissions Reductions/CO ₂ Emissions from Coal Combustion	CO ₂ /BTU ratio based on average state values in EIA (1992)	Fraction = [CO ₂ equivalent of CH ₄ emissions reductions (lbs)] / [1996 coal production (tons) x BTUs/ton x CO ₂ emitted lbs/BTU x 99% (fraction oxidized)]

Data Item	Sources	Calculations
BTU Value of Recovered Methane/BTU Value of Coal Produced	BTU/ton value for coal production based on information in Keystone or on average state values from EIA (1992)	Fraction = $\frac{[1996 \text{ CH}_4 \text{ liberated (cf/yr)} \times \text{rec. efficiency} \times 1000 \text{ BTUs/cf}]}{[1996 \text{ coal production (tons)} \times \text{BTUs/ton}]}$
Power Generation Potential		
Electricity Supplier	Directory of Electric Utilities	
Potential Electric Generating Capacity		Capacity = $\frac{\text{Estimated CH}_4 \text{ liberated in cf/day} \times \text{recovery efficiency} \times 1 \text{ day/24 hours} \times 1000 \text{ BTUs/cf} \times \text{kwh/11000 BTUs}}{11000}$
Mine Electricity Demand	Mine electricity needs (24 kwh/ton) is based on ICF Resources (1990a) Ventilation systems are assumed to account for 25% of total electricity demand and to run 24 hours a day (8760 hours/year). Other mine operations are assumed to account for 75% of electricity demand and to run 16 hours a day 220 days per year (3520 hours/year).	<p>Demand (MW) = Demand from Ventilation Systems + Demand from Mine Operations + Demand from Prep Plant</p> <p>Demand (MW) ventilation systems = $\frac{[25\% \times 24 \text{ kwh/ton} \times \text{tons/year}]/[8760 \text{ hours/year}]}{1000}$</p> <p>Demand (MW) mine operations = $\frac{[75\% \times 24 \text{ kwh/ton} \times \text{tons/year}]/[3520 \text{ hours/year}]}{1000}$</p> <p>Demand (GWh/year) = Demand from Mine + Demand from Prep. Plant</p> <p>Demand from Mine = $\frac{[24 \text{ kwh/ton} \times \text{tons/year}]}{10^6}$</p> <p>Demand from Prep. Plant = $\frac{[6 \text{ kwh/ton} \times \text{tons/year}]}{10^6}$</p>

Data Item	Sources	Calculations
Prep Plant Electricity Demand	Based on Keystone Coal Manual (1997) and Coal magazine annual Prep Plant surveys. If tons processed per year at the prep plant is available in Keystone, then that value is used. Otherwise, coal processed is assumed to be equal to mine production. Prep plant electric needs of 6 kwh/ton based on ICF Resources (1990a). Prep plants are assumed to operate 3520 hours/year.	Demand (MW) prep plant = [6 kwh/ton x tons/year]/ 3520 hours/year]
Pipeline Potential Potential Annual Gas Sales All other information	 ICF Resources (1990b)	 Estimated methane liberated (mmcf/d) x 365 days/yr x recovery efficiency
Other Utilization Potential Name of Coal Fired Boiler Located Near Mine (if any) Distance to Boiler Nearby Industrial/Institutional Facilities	ESA (1991) ESA (1991) Local chambers of commerce, industry publications, local phone books, etc.	